CHAPTER 8: LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

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CHAPTER 8: LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

8.1 INTRODUCTION

This chapter of the Technical Support Document (TSD) presents the Department's life-cycle cost (LCC) and payback period (PBP) analyses. It describes the method used for analyzing the economic impacts of possible standards on consumers. The effect of standards on consumers includes a change in operating expense (usually decreased) and a change in purchase price (usually increased). The LCC analysis produces two basic outputs to describe the effect of standards on consumers:

- Life-cycle cost is the total (discounted) cost that a consumer pays over the lifetime of the equipment, including purchase price, installation cost, and operating expenses.

- Payback period measures the amount of time it takes consumers to recover the assumed higher purchase expense of more energy-efficient equipment through lower operating costs.

This chapter presents inputs and results for the LCC analysis, as well as key variables, current assumptions, and computational equations. The Department performed the calculations discussed here in a series of Microsoft Excel spreadsheets, which are accessible over the Internet. Section 8.7 of this document contains details and instructions for using the spreadsheets. There are five appendices to this chapter: 1) a complete set of results is presented in Appendix 8A; 2) Appendix 8B discusses uncertainty and variability; 3) the utility sample is fully detailed in Appendix 8C; 4) a complete set of sensitivity results for design lines 1, 7, and 12 is presented in Appendix 8D; and 5) average baseline transformer design properties are presented in Appendix 8E.

8.1.1 General Approach for Life-Cycle Cost Analysis

Recognizing that each transformer customer is unique, the Department calculated the LCC and PBP for a representative sample (i.e., a distribution) of individual transformers. In this manner, the Department's analysis explicitly recognizes that there is both variability and uncertainty in its inputs. The Department used Monte Carlo simulations to model the distributions of inputs.

The Monte Carlo process statistically captures input variability and distribution without testing all possible input combinations. The results are expressed as the number of transformers experiencing economic impacts of varying magnitudes. The Department developed the LCC model using Excel spreadsheets combined with Crystal Ball, a commercially available add-in program. A detailed explanation of the Monte Carlo simulation process and the use of probability distributions in this analysis are contained in Appendix 8B.

The LCC results are displayed as distributions of impacts compared to the baseline conditions. The Department presents tabular results at the end of this chapter; they are based on 10,000 samples per Monte Carlo simulation run. In addition, Appendix 8A consists of graphic displays illustrating the following analysis results for each standard level of each design line:

- a cumulative probability distribution showing the percentage of transformers that would have a net savings due to standards, and

- a frequency chart depicting variation in LCC for each standard level considered in the analysis.

The Department developed two approaches for the LCC calculations: one for liquid-immersed transformers and one for dry-type transformers. Because the large majority of liquid-immersed transformer owners are utilities, the liquid-immersed LCC calculations used utility marginal costs and distribution markups that do not include a wholesaler and contractor markup. In contrast, because the majority of dry-type transformer owners are commercial and industrial enterprises, the Department used the monthly marginal electricity costs and complete distribution markups for the dry-type transformer LCC calculation. For simplicity, the Department used only one type of LCC calculation for each design line of transformer based on the majority owner type of that category.

8.1.2 The Baseline Scenario

In developing appliance standards, the Department has traditionally used an existing standard level as a baseline from which it calculates the impact of any candidate standard level. Because distribution transformers are not currently subject to a national energy-efficiency standard, the Department developed an alternative approach to determine an appropriate baseline against which to compare various candidate standard levels. That alternative approach focuses on the mix of selection criteria customers are known to employ when purchasing transformers. Those criteria include first costs, as well as what is known in the transformer industry as total owning cost (TOC), used by some customers as an alternative criterion to first costs. The TOC method combines first costs with the cost of losses. Purchasers of distribution transformers, especially in the utility sector, have long used the TOC method to determine which transformers to purchase.[1, 2] To establish the LCC baseline scenario, the Department developed a process that uses distributions of efficiencies and an estimated percent of transformers currently being purchased using the TOC method. That scenario represents the range of transformer costs and efficiencies that transformer purchasers would likely experience without national energy-efficiency standards in place.

8.1.3 Total Owning Cost

The utility industry developed TOC evaluation as an easy-to-use tool to reflect the unique financial environment faced by each transformer purchaser. To express variation in such factors as the cost of electric energy and capacity and financing costs, the utility industry developed a range of evaluation factors, called A and B values, in their calculations. A and B are the equivalent first costs of the no-load and load losses (in $/watt), respectively. No-load losses refer to the core losses that are roughly constant once the transformer is energized; load losses are the coil losses that vary roughly with the square of the load on the transformer.

The TOC transformer purchasers (i.e., those using the TOC method to determine which units to buy) assign an economic value to transformer losses: A and B parameters. Then they add these costs to the first cost of acquiring the transformer to derive TOC. The equation for calculating transformer TOC is:

$$TOC = FC + (A \times NLL) + (B \times LL) \qquad \textbf{Eq. 8.1}$$

where:

FC	=	first cost of acquiring the transformer, including purchase price and installation cost (2004$),
A	=	the no-load loss valuation parameter ($/W),
NLL	=	the no-load loss at nameplate load (W),
B	=	the load loss valuation parameter ($/W), and
LL	=	the load loss at nameplate load (W).

Throughout the LCC analysis, DOE expresses monetary values in units of year 2004 real dollars.

8.2 LIFE-CYCLE COST METHOD

8.2.1 Definition

The basis for both the LCC analysis and the spreadsheet model is the LCC equation. The LCC equation reflects both the first costs of a transformer and the present value of the operating costs over the service life of the transformer.

The LCC equation is:

$$LCC = FC + \sum_{1}^{Lifetime} \left(OC_n / (1 + Drate)^n \right) \qquad \textbf{Eq. 8.2}$$

where:

FC	=	the first cost (2004$),
n	=	the index for the year of operation (yr),
Lifetime	=	the service life of the transformer,
OC_n	=	the operating cost in year *n*, including the value of the losses and maintenance costs (2004$/yr), and
Drate	=	the discount rate applied to the calculation (%).

8.2.2 Life-Cycle Cost Spreadsheet Key Steps

While the LCC is a simple equation, the Department's LCC spreadsheet model takes into account the dynamic nature of a variety of inputs over the service life of a transformer. A simplified flowchart (Figure 8.2.1) illustrates the key steps implemented in the LCC spreadsheet: the main inputs, the key computational steps, and the important outputs.

Sections 8.2.2.1 through 8.2.2.11 describe, in step-by-step fashion, the computational flow of the LCC model as shown in the flowchart. Following this explanation of the analytical steps in the model, the Department presents the specific inputs that it developed and then used in the LCC model for this rulemaking. Next, DOE presents the results of the LCC model runs for the various design lines. Finally, the Department presents the key sensitivities to those results.

The LCC process is a means of determining the financial impact resulting from the imposition of energy-efficiency standards for distribution transformers from the perspective of the consumer, or owner, of the transformer. Several types of information are necessary for this calculation: the first costs of transformers with and without standards, the operating costs of the transformers with and without standards, the year the standard is to become effective, and the lifetime of transformers. For ease of comparison, DOE presents all costs in present values, which requires using discount rates. The Department’s methods for determining these inputs are explained in more detail in the LCC Inputs section (section 8.3).

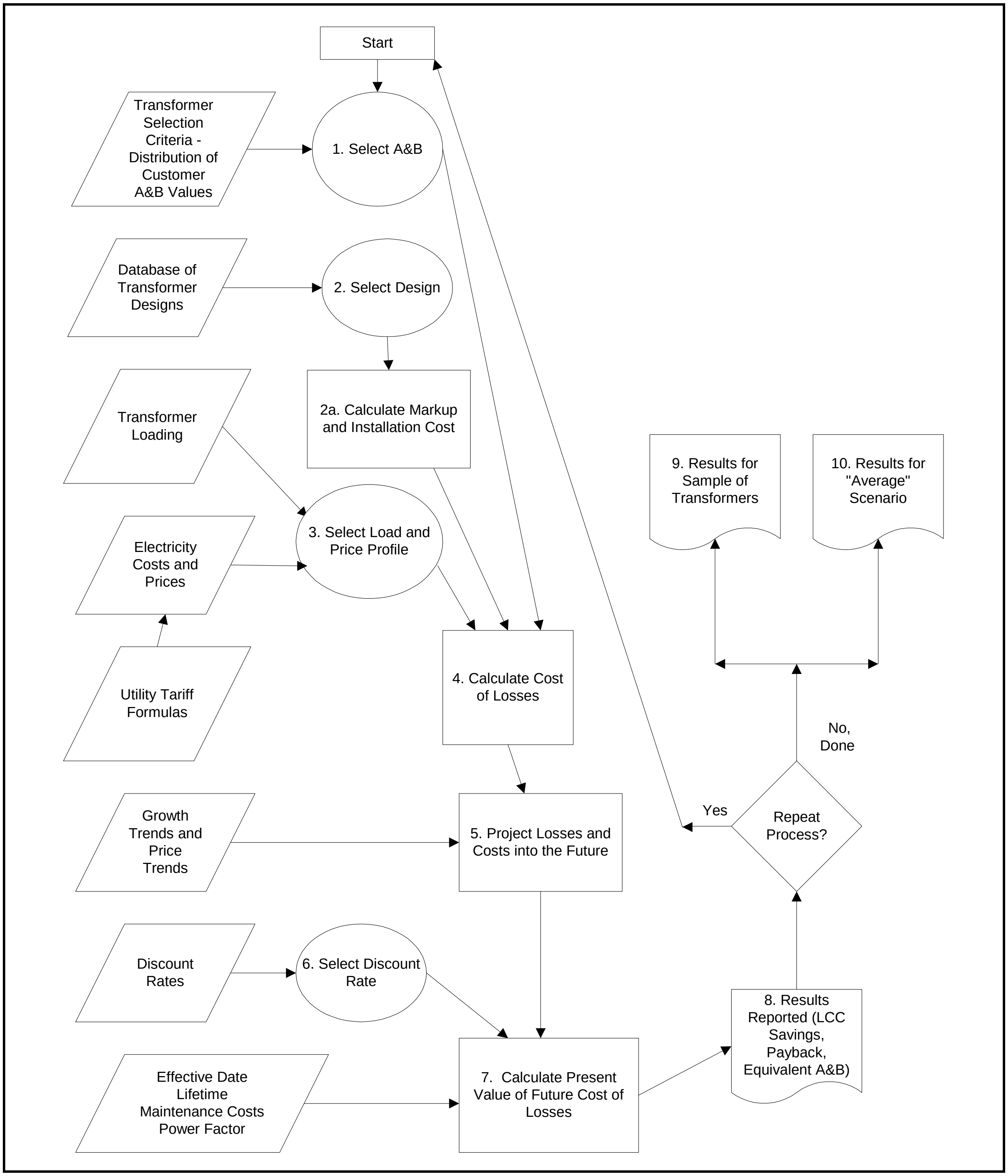

Figure 8.2.1 Transformer Life-Cycle Cost Spreadsheet Model Flowchart

8.2.2.1 Step #1: Select A & B

Step#1: Select customer choice A and B parameters from the choices on the "A & B Dist" worksheet. The purpose of this step is to establish the current purchasing decision environment. For liquid-immersed transformers, based on National Electrical Manufacturers Association (NEMA) comments, the Department assumed that 25 percent are purchased based on lowest first cost and 75 percent are purchased using TOC evaluation.[3]

Commercial and industrial (C&I) entities can also apply an A- and B-based evaluation process for dry-type transformer purchase evaluation. While the analytic process for determining A and B values used by C&I purchasers is different from that used by electric utilities, the fundamental meanings of A and B are the same for both groups of transformer purchasers.

The LCC spreadsheet simulates different transformer purchase evaluation scenarios with three different A and B distributions. All liquid-immersed transformer design lines use a common set of scenarios, low-voltage, dry-type design lines use a different, but also common, set of scenarios, and medium-voltage, dry-type design lines also use a different but common set of scenarios. The specific inputs used in these three scenarios are shown in section 8.3 of this TSD, as well as in the "A & B Dist" worksheet of the LCC spreadsheets themselves. These scenarios can be selected using the "Transformer Customer A's and B's" pull-down menu on the "Summary" worksheet. Step #2 below explains the application of these A & B distributions when actual transformer designs are selected.

8.2.2.2 Step #2: Select Designs That Meet a Chosen Candidate Standard Level

Step #2: Select designs and a candidate standard level. The purpose of this step is to select a candidate standard level and its associated transformer designs to evaluate with the LCC spreadsheet. The Department used NEMA's TP 1-2002[1] as the first possible candidate standard level to evaluate, and developed five additional candidate standard levels based on information obtained from the engineering analysis. The additional candidate standard levels are selected based on the properties of the distribution of engineering designs. The highest candidate standard level is the highest efficiency for which there are at least 10 compliant designs from the engineering analysis. The next highest standard level is that level which has the greatest energy savings yet approximately has the same or lower LCC as the average baseline transformer. The next highest standard level is that level with the minimum LCC, and the next two lower levels are equally spaced in efficiency between the minimum LCC efficiency level and the TP 1-2002 efficiency. The engineering analysis yielded a cost-efficiency relationship in the form of manufacturer selling prices, no-load losses, and load losses for a wide range of realistic transformer designs. This set of data provides the LCC model with a distribution of transformer design choices. (See the "Design Table" worksheet, a condensed version of the engineering analysis output.) After the user chooses a candidate standard level, the spreadsheet selects from its database of designs the subset of designs that satisfy the selected candidate standard level and another set of designs that satisfy the baseline scenario.

In addition to the economic value of losses, other factors may affect design selection. The Department accounted for such factors by including a random cost factor that is added to the transformer's first costs. Using this factor, the Department captured the range of typical real-world cost variation in the first cost of the transformer. The Department modeled this random cost factor as a uniformly distributed random number that can either raise or lower the first cost of the transformer by up to 15 percent. The spreadsheet selects the transformer design that has the lowest TOC (including the random cost factor) for the customer. For each iteration cycle, a design is chosen based on A and B distributions from Step #1.

Step #2a: Calculate markup and installation costs. For liquid-immersed transformers, which are typically purchased directly by the utilities from manufacturer representatives, DOE considered the transformer purchase price to be the manufacturer selling price plus a distributor markup, the shipping cost, and sales tax. Installation costs are added separately. For dry-type transformers, the distribution channel includes various intermediaries who add their own costs to the manufacturer selling price. These costs include a manufacturer markup, distribution markup, contractor markup, shipping cost, installation costs, and sales tax.

Key inputs for this step include markup and installation costs. The Department presents its specific values for these inputs in Chapter 7.

8.2.2.3 Step #3: Load and Price Profile

Step #3: The spreadsheet model dynamically selects a sample transformer load profile from distributions derived from available data. To estimate the impact of transformer losses on commercial and industrial companies' electricity bills, the Department modeled the relationship between monthly transformer load characteristics and customer demand and usage. The Department derived distributions of load parameters from hourly load data available to it. For liquid-immersed transformers, the Department developed an hourly transformer load simulation model to capture the dynamics and economics of transformer loads.

The load profiles and characteristics are provided in the "Load & Price Parameters" worksheet of the LCC spreadsheet for liquid-immersed transformers and in the "Demand & Usage" worksheet of the LCC spreadsheet for dry-type transformers.

For the cost of electricity, the Department used the marginal cost of electricity for liquid-immersed transformers. For dry-type transformers, it developed a method to calculate customer monthly bills. For both transformer types, the Department calculated the total cost of electricity both with and without transformer losses and took the difference to calculate the incremental electricity costs. Section 8.3.5 provides a detailed discussion of the electricity price analysis.

8.2.2.4 Step #4: Calculate Cost of Losses

Step #4: The spreadsheet model calculates the costs of losses by combining the incremental impacts of no-load and load losses with the loss coefficients of the design, the monthly customer load characteristics (demand and usage), and the cost of electricity. In this step, the spreadsheet combines the no-load losses, load losses, and electricity price information for each transformer in the baseline scenario and in the candidate standards scenario. Subsequent steps extend these costs of losses into the future and then convert them back to present values.

8.2.2.5 Step #5: Project Losses and Costs into the Future

Step #5: The spreadsheet model projects losses and costs into the future, based on load growth assumptions and a forecast of future changes in electricity price. Spreadsheet users can select different load growth and future electricity price scenarios or use the medium assumptions of one percent load growth and DOE's Energy Information Administration (EIA) reference scenarios from the *Annual Energy Outlook 2005* (*AEO2005*).[4] The model applies the selected options for load growth and price trends to the current cost of losses that were calculated in Step #4. Step #5 results in a projection of those losses and costs into the future. The Department presents its specific load growth and electricity price trends in the LCC inputs section (section 8.3) of this chapter.

8.2.2.6 Step #6: Select Discount Rate

Step #6: The spreadsheet model selects a discount rate from the discount rate distribution. To discount the future stream of costs into a present value, it is necessary to select a discount rate. The LCC spreadsheet selects a discount rate from a weighted sample of discount rate inputs derived from financing costs of transformer purchasers. The Department presents its specific discount rates in the LCC inputs section (section 8.3) of this chapter.

8.2.2.7 Step #7: Calculate Present Value of Future Cost of Losses

Step #7: The spreadsheet model calculates the present value of future operating costs and losses and the present worth per watt of no-load and load losses. This step applies the discount rate of Step #6 to the future costs of losses from Step #5 to produce a single, present-valued number. In addition to the costs from Step #5 above, the calculation uses as inputs the effective date of the standard, the transformer lifetime, maintenance costs, and a power factor.

8.2.2.8 Step #8: Results Reported

Step #8: The spreadsheet model records the LCC, LCC savings, payback period, and other results for inclusion in the distribution of results. This is a reporting step. The model uses the inputs in a set of calculations and reports the results. Depending on the application, different kinds of results can be reported, e.g., LCC savings, payback periods, or equivalent A and B values. The default report includes LCC savings for each candidate standard level over the baseline scenario; it reports the mean value, plus the percentage of purchasers with positive LCC savings. Payback periods are reported separately.

8.2.2.9 Step #9: Results of Distribution of Transformers

Step #9: The spreadsheet model repeats the calculation until reaching the specified maximum number of iterations. When applying a Monte Carlo simulation process, the model performs a user-defined number of iterations and reports the results as distributions. Based on the Department's experience with prior rulemakings' use of results expressed as distributions, 10,000 iterations in a Monte Carlo simulation capture sufficient variability.

8.2.2.10 Step #10: Results for "Average" Scenario

Step #10: The spreadsheet model reports the results of the calculation for the "Average" scenario on the "Summary" worksheet. The "Average" scenario allows users to produce provisional answers without performing a Monte Carlo simulation. The Summary worksheet of the LCC spreadsheet shows the results from this scenario. For liquid-immersed transformers, the Department extracted the marginal demand cost and marginal energy cost used in the average scenario calculation from a representative LCC Monte Carlo simulation. Similarly, for dry-type transformers, the Department extracted an average marginal demand and energy rate from a sample dry-type Monte Carlo simulation.

8.2.2.11 Repeat Process

The specific number of iterations required for the Monte Carlo simulation is implemented through the <Repeat Process> decision box. When the desired number of iterations has been reached, the model ends the simulation process and generates result reports.

8.3 LIFE-CYCLE COST INPUTS

This section presents the specific LCC inputs used in the spreadsheet model and provides definitions and data sources for each component. This section also elaborates on the specifics of how the LCC spreadsheets apply certain user-chosen inputs to the LCC model. The specific inputs to the model, in the order in which they appear in the left-hand side of the LCC flowchart (Figure 8.2.1), are:

- A and B Transformer Selection Parameters and Usage Rates
- Database of Transformer Designs
- Markup and Installation Costs
- Transformer Loading
- Electricity Costs and Prices
- Load Growth Trends
- Electricity Cost and Price Trends
- Discount Rate
- Effective Date of Standard
- Transformer Service Life
- Maintenance Costs
- Power Factor

8.3.1 A and B Transformer Selection Parameters and Usage Rates

The A and B transformer selection parameters that DOE used in the formal TOC calculation can also be used more generally to characterize the value that transformer purchasers place on reducing no-load and load losses in transformers. This is because the A and B parameters express a measure of the economic value of loss reduction in terms of dollars per watt of reduced losses. The ability to measure the economic value of loss reduction in units of dollars per watt is independent of the actual method for estimating that value. The main assumption implicit in using A and B values to represent customer transformer choice decisions is that the value of loss reduction is proportional to the amount by which losses are reduced. Given this wider applicability of the TOC formulation to the expression of loss valuations, the Department used A and B parameters to formulate a transformer customer choice model.

To represent the potential range of purchaser valuations given to transformer no-load and load losses, the Department developed three A and B distributions to represent three customer choice scenarios for each LCC calculation. The key difference among the three scenarios is the fraction of purchasers who are estimated to place a value on reducing transformer losses. Those who place a value on reducing such losses are described as *evaluators*, while those who do not consider transformer losses during a purchase are termed *non-evaluators*. The scenario representing non-evaluation for all purchases has 0 percent evaluators, while the scenario representing evaluation for all purchases has 100 percent evaluators. For liquid-immersed transformers, many purchases are evaluated, so the Department's default scenario is an evaluation rate of 75 percent, which is approximately consistent with data provided by NEMA[3] regarding the fraction of transformers that are TP 1-compliant. Table 8.3.1 provides the evaluation usage rates, for the three evaluation scenarios just described, for a range of different A values for liquid-immersed transformers. For low-voltage, dry-type design lines, few purchasers consider transformer losses as part of the purchase decision, so DOE developed a default medium scenario in which 10 percent are evaluators, which is approximately consistent with the data provided by NEMA regarding the fraction of transformers that are TP 1-compliant (see Table 8.3.2). For medium-voltage, dry-type transformers, the Department assumed 50 percent evaluators for small-capacity transformers—design line (DL) 9 and DL 11 (Table 8.3.3)—and 80 percent for large-capacity—DLs 10, 12, and 13 (Table 8.3.4). These default scenarios produced results roughly consistent with NEMA data regarding the fraction of transformers compliant with TP 1 in the current market. The 0 percent and 100 percent evaluation scenarios are available to test the LCC sensitivity to changes in the percentage of transformers purchased using evaluation. The Department estimated the mean value of A for evaluators from values provided by stakeholders and collected from public transformer purchase bids available on the Internet. Then, recognizing that there is substantial variability in the value that transformer purchasers may place on reducing losses, the Department created a distribution that represented this variability, as illustrated in Tables 8.3.1 through 8.3.4. The Department used a slightly smaller average A value of $2.5/watt for dry-type transformers based on stakeholder comments.

Table 8.3.1 Distributions of A Values for Liquid-Immersed Transformers: Three Scenarios with Usage Percentages

0% Non-Evaluating	
A *$*	Probability *%*
0.00	100.00

75% Medium-Evaluating	
A *$*	Probability *%*
0.00	25.00
0.39	0.64
0.77	1.28
1.16	2.24
1.54	3.20
1.93	4.27
2.31	5.34
2.70	6.01
3.08	6.68
3.47	6.68
3.85	6.68
4.24	6.12
4.62	5.56
5.01	4.77
5.39	3.97
5.78	3.23
6.16	2.48
6.55	1.93
6.93	1.38
7.32	1.03
7.70	0.69
8.09	0.50
8.47	0.31

100% High-Evaluating	
A *$*	Probability *%*
0.00	0.00
0.39	0.85
0.77	1.71
1.16	2.99
1.54	4.27
1.93	5.70
2.31	7.12
2.70	8.01
3.08	8.90
3.47	8.90
3.85	8.90
4.24	8.16
4.62	7.42
5.01	6.36
5.39	5.30
5.78	4.30
6.16	3.31
6.55	2.58
6.93	1.84
7.32	1.38
7.70	0.92
8.09	0.67
8.47	0.42

Table 8.3.2 Distributions of A Values for Low-Voltage, Dry-Type Transformers: Three Scenarios with Usage Percentages

0% Non-Evaluating	
A *$*	**Probability** *%*
0.00	100.00

10% Medium-Evaluating	
A *$*	**Probability** *%*
0.00	90.00
0.25	0.19
0.50	0.37
0.75	0.56
1.00	0.74
1.25	0.87
1.50	0.99
1.75	0.99
2.00	0.99
2.25	0.89
2.50	0.79
2.75	0.66
3.00	0.53
3.25	0.42
3.50	0.30
3.75	0.23
4.00	0.15
4.25	0.11
4.50	0.07
4.75	0.05
5.00	0.03
5.25	0.02
5.50	0.01

100% High-Evaluating	
A *$*	**Probability** *%*
0.00	0.00
0.25	1.86
0.50	3.72
0.75	5.57
1.00	7.43
1.25	8.67
1.50	9.91
1.75	9.91
2.00	9.91
2.25	8.92
2.50	7.93
2.75	6.61
3.00	5.29
3.25	4.15
3.50	3.02
3.75	2.27
4.00	1.51
4.25	1.09
4.50	0.67
4.75	0.47
5.00	0.27
5.25	0.18
5.50	0.10

Table 8.3.3 Distributions of A Values for Small-Capacity, Medium-Voltage, Dry-Type Transformers (DL 9 and DL 11): Three Scenarios with Usage Percentages

0% Non-Evaluating		50% Medium-Evaluating		100% High-Evaluating	
A *$*	**Probability** *%*	**A** *$*	**Probability** *%*	**A** *$*	**Probability** *%*
0.00	100.00	0.00	50.00	0.00	0.00
		0.25	0.93	0.25	1.86
		0.50	1.86	0.50	3.72
		0.75	2.79	0.75	5.57
		1.00	3.72	1.00	7.43
		1.25	4.34	1.25	8.67
		1.50	4.95	1.50	9.91
		1.75	4.95	1.75	9.91
		2.00	4.95	2.00	9.91
		2.25	4.46	2.25	8.92
		2.50	3.96	2.50	7.93
		2.75	3.30	2.75	6.61
		3.00	2.64	3.00	5.29
		3.25	2.08	3.25	4.15
		3.50	1.51	3.50	3.02
		3.75	1.13	3.75	2.27
		4.00	0.76	4.00	1.51
		4.25	0.55	4.25	1.09
		4.50	0.34	4.50	0.67
		4.75	0.23	4.75	0.47
		5.00	0.13	5.00	0.27
		5.25	0.09	5.25	0.18
		5.50	0.05	5.50	0.10

Table 8.3.4 Distributions of A Values for Large-Capacity, Medium-Voltage, Dry-Type Transformers (DL 10, DL 12, and DL 13): Three Scenarios with Usage Percentages

0% Non-Evaluating		80% Medium-Evaluating		100% High-Evaluating	
A $	**Probability %**	A **$**	**Probability %**	**A $**	**Probability %**
0.00	100.00	0.00	20.00	0.00	0.00
		0.40	1.49	0.40	1.86
		0.80	2.97	0.80	3.72
		1.20	4.46	1.20	5.57
		1.60	5.95	1.60	7.43
		2.00	6.94	2.00	8.67
		2.40	7.93	2.40	9.91
		2.80	7.93	2.80	9.91
		3.20	7.93	3.20	9.91
		3.60	7.13	3.60	8.92
		4.00	6.34	4.00	7.93
		4.40	5.29	4.40	6.61
		4.80	4.23	4.80	5.29
		5.20	3.32	5.20	4.15
		5.60	2.42	5.60	3.02
		6.00	1.81	6.00	2.27
		6.40	1.21	6.40	1.51
		6.80	0.87	6.80	1.09
		7.20	054	7.20	0.67
		7.60	0.38	7.60	0.47
		8.00	0.21	8.00	0.27
		8.40	0.15	8.40	0.18
		8.80	0.08	8.80	0.10

For each value of A that a transformer purchaser may have, there is a range of possible B values that are consistent with the particular A value. (B values relate to the value associated with the load losses.) In general, the ratio of B to A is a measure of the relative importance of load losses and no-load losses. For a transformer that is constantly loaded at 100 percent of rated capacity, the value of B and A should be the same, since both load and no-load losses will always be at their rated values. Load losses increase with the square of the loading and transformer mean loadings are almost always below 100 percent. Therefore, in practice, B is always less than A, and is approximately equal to A times the square of the expected loading (when peak load considerations are neglected).

The Department characterized the relationship between customer selection of B and A values by selecting five possible values for the B:A ratio. For liquid-immersed transformers, the Department selected a B:A ratio of 0.30 (approximately the square of 50 percent) as a reasonable median value, based on the evaluation parameter data for utilities available to the Department. For dry-type transformers, the Department estimated the median ratio of B:A as the square of the transformer efficiency standard evaluation loading. To model variability in the ratio of B:A, the Department selected four other values for the ratio between 0 and 1: 0.6 × *MedianBA*, 0.8 × *MedianBA,* 0.15 + 0.85 × *MedianBA*, and 0.35 + 0.65 × *MedianBA,* where *MedianBA* is the median value of the B:A ratio. These four values of the ratio provide a distribution between 0 and 1 that has the estimated median value for the B:A ratio and that matches the properties of the evaluation parameter data available to the Department.

As described above, the Department selected slightly different median B:A ratios for liquid-immersed and dry-type transformers. The higher B:A ratio for liquid-immersed transformers reflects the more careful evaluation of peak load impacts of load losses on the part of utilities. The B:A ratio for dry-type customers reflects an assumption that commercial and industrial customers will tend to value their load losses with an average electricity price.

The Department calculated present worth factors for no-load and load losses so that stakeholders could compare the Department’s LCC results with the A and B values used in TOC calculations. The Department defines the present worth factor for transformer losses as the present value of losses divided by the rated loss. There are distinct present worth factors for no-load and load losses. The present worth factors are different from the A and B values used for TOC calculations because the method for calculating the present value of losses is consistent with the methods of efficiency standard LCC calculations and differs slightly from the method described in the Institute of Electrical and Electronics Engineers' *Draft Guide for Distribution Transformer Loss Evaluation.*[2]

To summarize, the Department characterized transformer purchases with respect to efficiency in terms of two economic valuation parameters. The parameter A expresses the value that a customer gives to reducing no-load losses in dollars per watt, while the parameter B expresses the value given to reducing load losses at rated load. The Department described purchase behavior in terms of evaluators who place a value on reducing losses, and non-evaluators who place no value on reducing losses in their purchase behavior. The Department investigated three scenarios as sensitivities. For liquid-immersed transformers, the scenarios are 0 percent evaluators, 75 percent evaluators, and 100 percent evaluators. For low-voltage, dry-type transformers, the scenarios are 0 percent evaluators, 10 percent evaluators, and 100 percent evaluators. For small-capacity, medium-voltage, dry-type transformers, the scenarios are 0 percent evaluators, 50 percent evaluators, and 100 percent evaluators and for large-capacity, medium-voltage, dry-type transformers, the scenarios are 0 percent evaluators, 80 percent evaluators, and 100 percent evaluators. The Department selected evaluation percentages that are roughly consistent with NEMA data regarding the fraction of transformers compliant with TP 1 in the current market. For evaluators, the Department uses a distribution of A and B values to characterize their behavior. The mean of the distribution of A values is determined from stakeholder and public data regarding evaluation parameters available to the Department. Once the Department chose the A value, it then chose a value for B of less than A, using a B:A ratio. The Department based the B:A ratio on the statistical characteristics of the evaluation parameter data that is available.

8.3.2 Database of Transformer Designs

Establishing a relationship between cost and efficiency is an integral part of the rulemaking process. For transformers, DOE derived this relationship from an engineering analysis database of selling prices, no-load losses, and load losses for a wide range of realistic transformer designs contained in the LCC spreadsheets. The Department used a commercial transformer design software company, Optimized Program Service Inc., and its software to create the database of designs. The database consists of a wide range of efficiencies and manufacturer sale prices (including a predetermined manufacturer markup) to represent the variability of designs in the marketplace. The engineering analysis (see Chapter 5) provides more detail on the structure and method used to generate this database of transformer designs.

8.3.3 Markup and Installation Costs

Markup, shipping costs, sales tax, and installation costs are the costs associated with bringing a manufactured transformer into service as an installed piece of electrical equipment.

For liquid-immersed transformers, which are typically purchased directly by the utilities from manufacturers, DOE considered the transformer purchase price to be the manufacturer selling price plus a distributor markup, the shipping cost, and sales tax. Installation costs are added separately. For dry-type transformers, the distribution channel includes various intermediaries who add their own costs to the manufacturer selling price. These costs include a manufacturer markup, distribution markup, contractor markup, shipping cost, installation costs, and sales tax. See Chapter 7 for a detailed discussion of the markup calculations.

8.3.4 Transformer Loading

To estimate the economic burdens and benefits of efficiency improvements, the Department characterized the energy use and losses of the equipment being analyzed. To characterize transformers' energy use and losses, the Department estimated the loads on them. Because the application of distribution transformers varies significantly by type of transformer (liquid-immersed or dry-type) and ownership (electric utilities own liquid-immersed 95 percent of the time, commercial/industrial entities use mainly dry-type), the Department performed two separate load analyses for use in the evaluation of distribution transformer efficiency: one load analysis for liquid-immersed transformers and a second load analysis for dry-type transformers.

Chapter 6 describes these two separate load analyses.

8.3.5 Electricity Price Analysis

This section describes the electricity price analyses the Department used to develop the energy portion of the annual operating expenses for distribution transformers. The electric power industry is currently in a state of transition between two different business models, from regulated monopoly utilities providing bundled service to all customers in their service area, to a system of deregulated, independent suppliers who compete for customers. While it is unclear if and when this transition will be completed, it is possible that, in the near future, customers will see a very different pricing structure for electricity. To account for the impacts of this situation on the LCC, the Department performed two types of load analysis for use in the evaluation of distribution transformer efficiency. The first type of analysis investigated the nature of hourly transformer loads, their correlation with the overall utility system load, and their correlation with hourly electricity costs and prices. The second type of analysis estimated the impacts of transformer loads and the resultant transformer losses on the monthly electricity usage, demand, and electricity bills of C&I customers. The Department refers to the two analyses as *hourly* and *monthly* analyses, respectively. The Department used the hourly analysis for the economic analysis of liquid-immersed transformers, which are predominantly owned by utilities that can see costs that vary by the hour. The Department used the monthly analysis for the evaluation of dry-type transformers, which are typically owned by C&I establishments that see monthly electricity bills.

8.3.5.1 Hourly Marginal Electricity Price Model for Liquid-Immersed Transformers

For liquid-immersed transformers, the Department used marginal electricity prices. Marginal electricity prices are the prices experienced by utilities for the last kilowatt-hours (kWh) of electricity produced. A utility's marginal price can be higher or lower than its average price, depending on the relationships between capacity, generation, transmission, and distribution costs. The general structure of the hourly marginal cost equation divides the costs of the electricity into capacity components and energy cost components. The capacity components include generation capacity, transmission capacity, and distribution capacity. Capacity components also include a reserve margin needed to ensure system reliability. Energy cost components include a marginal cost of supply that varies by the hour, factors that account for losses, and cost recovery of associated marginal expenses. The Department applied this specific equation to calculate the marginal cost of supply of electricity to cover transformer losses. The equation is:

$$\begin{aligned} MEC = {} & (1 + CM) \times (GC \times IGC + TC \times ITC + DC \times IDC) + \\ & (LAF \times EC(hour) + RF) \times IEU(hour) \end{aligned} \qquad \textbf{Eq. 8.3}$$

where:

MEC	=	marginal electricity cost (2004$),
CM	=	system capacity margin required for reliability,
GC	=	unit cost of generation capacity ($/kW),
IGC	=	incremental system capacity required by the load (kW),
TC	=	unit cost of transmission capacity ($/kW),
ITC	=	incremental transmission capacity required by the load (kW),
DC	=	unit cost of (non-transformer) distribution capacity ($/kW),
IDC	=	incremental distribution capacity required by the load (kW),
LAF	=	load adjustment factor, which is one plus the estimated system losses,
EC(hour)	=	hourly cost of electrical energy, either from a market or from fuel and operating cost data ($/kWh),
RF	=	additional cost recovery factor ($/kWh), and
IEU(hour)	=	incremental energy use (kWh).

The Department calculated the various inputs of this equation as follows:

Capacity Margin (CM). This is the fraction of extra or reserve capacity needed to ensure system reliability per unit of additional capacity requirement. The Department used the industry standard of 15 percent.

Unit Generation Capacity Cost (GC). This is the annualized cost-of-unit generating capacity for the particular load being served. It includes the cost of capital during the construction period, and the loss adjustment factor to account for losses between the generator and end-use load. The EIA's *Annual Energy Outlook 2003* (*AEO2003*) provides forecasts of such costs for different generation technologies.[5] This capacity cost depends on the type of load being served and the source of the electricity. For base load, DOE used the capacity cost for a pulverized coal plant, since this is currently the least-cost base-load technology. For peak loads, such as those associated with transformer peak-load losses, it used conventional combustion turbine capacity costs as the relevant marginal capacity cost. The Department obtained its estimates for generation capacity costs from data and estimates contained in the *AEO2003* forecast and adjusted the values to 2004 dollars using the gross domestic product (GDP) price deflator from *AEO2005*.[4] These costs are shown in Table 8.3.5 as reported in the *AEO2003* forecast in year 2000 dollars.

Table 8.3.5 Generation Capacity Costs

Technology	**Year**	**Cost** ***2000$/kW***
Conventional Pulverized Coal	2001	1,119
	2010	1,083
	2020	1,056
Conventional Gas Combined Cycle	2001	456
	2010	448
	2020	438
Conventional Gas Combustion Turbine	2001	339
	2010	333
	2020	326

Incremental Generation Capacity Requirement (IGC). This is the amount of generation capacity required by a load. For the core-loss component, this is equal to the core losses times the loss adjustment factor (see *LAF* below). For the load-loss component, DOE estimated this by multiplying the peak responsibility factor (PRF) by the transformer peak load and feeding the result to the load-loss equation. PRF is the fraction of the transformer peak that is coincident with the system peak. The Department calculated a first-year PRF. Note that there is a multi-year delay between the time when new capacity is contracted and when it becomes available. *AEO2003* capacity cost forecasts are expressed in terms of when the capacity is contracted. The Department translated this cost into the cost at first year of service by adding capital costs as determined by the discount rate. The Department annualized costs by applying the capital recovery factor to capacity costs, assuming that such capacity has a 30-year lifetime.

Unit Transmission Capacity Cost (TC). This is the annualized cost per unit for an increment of new transmission capacity. The Department obtained transmission capacity costs from the estimates made by EIA for each of 13 transmission regions in the *AEO2003* forecast. The Department used the value of $166/kW in year 2000 dollars and adjusted to 2004 dollars using the GDP price deflator from *AEO2005*, which is the average marginal transmission capacity cost for all 13 transmission regions.

Incremental Transmission Capacity Requirement (ITC). This is the amount of transmission capacity required by an incremental load. The Department assumed that the transmission capacity requirement is the same as the generation capacity requirement.

Unit Distribution Capacity Cost (DC). This is the cost per unit of distribution capacity. The Department used distribution capacity costs from the U.S. Federal Energy Regulatory Commission (FERC) Form 1 data on the investment in transformers, substations, lines, and feeders per unit of system peak[6] as analyzed and published by the Regulatory Assistance Project.[7] The Department used the average cost of distribution capacity per kilowatt of system peak, and assumed that the real price of distribution capacity is constant (i.e., has no trend up or down). The estimated distribution capacity cost for the analysis is $276/kW in year 2000 dollars and adjusted to 2004 dollars using the GDP price deflator from *AEO2005*.

Incremental Distribution Capacity Requirement (IDC). This is the amount of distribution capacity required by an incremental load. The Department assumed this to be the same as the peak incremental energy use.

Loss Adjustment Factor (LAF). The loss adjustment factor is the factor that one must multiply times an end-use load to estimate the amount of system electricity needed to supply that load. It is one plus the fractional losses in the system. The Department assumed it to have a constant value of 1.08.

Hourly Energy Cost (EC). This is the hourly marginal energy cost that DOE obtained from utility system lambda data or market data. Since DOE obtained this from market data, it assumed it to include generation capacity effects and the generation capacity cost to be zero.

Additional Cost Recovery Factor (RF). This is a factor that DOE added to the hourly energy cost to account for costs besides energy losses that are associated with supplying that energy. The Department obtained the per-kWh additional cost recovery factors in Table 8.3.6 using real-time pricing formulas from the utilities listed in the table. Such factors are necessary for marking up the cost of generation to account for other costs that scale with generation, but which are not included in such costs. Such costs may include accounts payable and accounts receivable and operating capital costs, which will have a component that scales with the volume of electricity sales.

Table 8.3.6 Representative Cost Recovery Factors

Utility	**Recovery Factor**
Illinois Power Company	0.5 cents/kWh (5-year contract)
Pacific Gas and Electric Co.	0.346 cents/kWh
PSI Energy Inc.	10% to 25% of $EC(hour) \times LAF$
Carolina Power and Light	20% of $EC(hour)$
Union Light, Heat, and Power Company	10% of $EC(hour) \times LAF$

Based on this range of observed cost-recovery factors, DOE assumed that the cost recovery factor is approximately 0.15 (i.e., 15 percent) of the cost of energy.

Incremental Energy Use (IEU). This is the incremental hourly energy use calculated from the transformer loading that is obtained from the formula for the transformer losses.

8.3.5.2 Monthly Tariff-Based Analysis for Dry-Type Transformers

This section gives an overview of the tariff-based analysis of electricity prices for dry-type transformers. The Department updated the utility tariffs used in the monthly analysis to 2004. While the electricity prices were updated, the Department used the same distribution of utilities as it used in the Advance Notice of Proposed Rulemaking (ANOPR) analysis which was derived from year 2000 data.

Selection of the Sample Utilities. The Department used three main criteria in developing the utility sample for the utility tariff formulas: 1) the sample of utilities should reflect the distribution of population across the country, with more utilities drawn from more populated areas; 2) the sample should reflect the proportion of customers served by privately owned (investor-owned utilities (IOUs) and power marketers) entities versus publicly owned utilities (municipals, cooperatives, State, and Federal); and 3) the sample should cover as many customers as possible. Data on utilities are available from the EIA through their Form 861 filings.[8] This form is filed annually by every utility that retails power to final consumers, and includes information on the total sales in MWh, total revenues, and the numbers of customers. Utilities supply this information separately for the residential, commercial, and industrial sectors. The Department used data from the year 2000 in this analysis.

The Department first screened the set of utilities in the EIA database to consider only those with customers in all three sectors (residential, commercial, industrial). It then computed, for each subdivision, the percentage of customers served by public versus private utilities. The Department chose the sample utilities to reflect the relative population of the subdivision and the proportion of public-to-private customers. In most areas, the Department included the largest utilities in the sample to maximize the number of customers represented, but it also included smaller private utilities and public utilities of all sizes. The final set of sampled utilities includes 49 privately owned and 41 publicly owned companies.

The EIA data for 2000 show that power marketers and other providers of unbundled retail services serve approximately two percent of the commercial customers in the country. Power marketers have the largest market share in New England, so the Department included one such company in its sample for this region. Appendix 8C contains a list of the sample utilities.

Subdivision of the Country. Because of the wide variation in electricity usage patterns, wholesale costs, and retail rates across the country, it is important to consider regional differences in models of electricity prices. For this reason, the Department divided the continental United States into 17 regions or subdivisions. To make maximum use of the location information in DOE's Commercial Building Energy Consumption Survey (CBECS),[9] the breakdown started with the nine census divisions. The Department further subdivided these to take into account significant climate variation and the existence of different electricity market or grid structures. The Department based climate divisions on the nine climate regions defined for the continental U.S. by the National Climactic Data Center.[10] In addition, it separated out Texas, Florida, New York, and California because their electric grids are operated independently. Figure 8.3.1 illustrates the results. In the figure, the subdivision numbers use the CBECS census code as the first digit. For example, census division 8 (Mountain) has been separated into two subdivisions, 8.1 and 8.2.

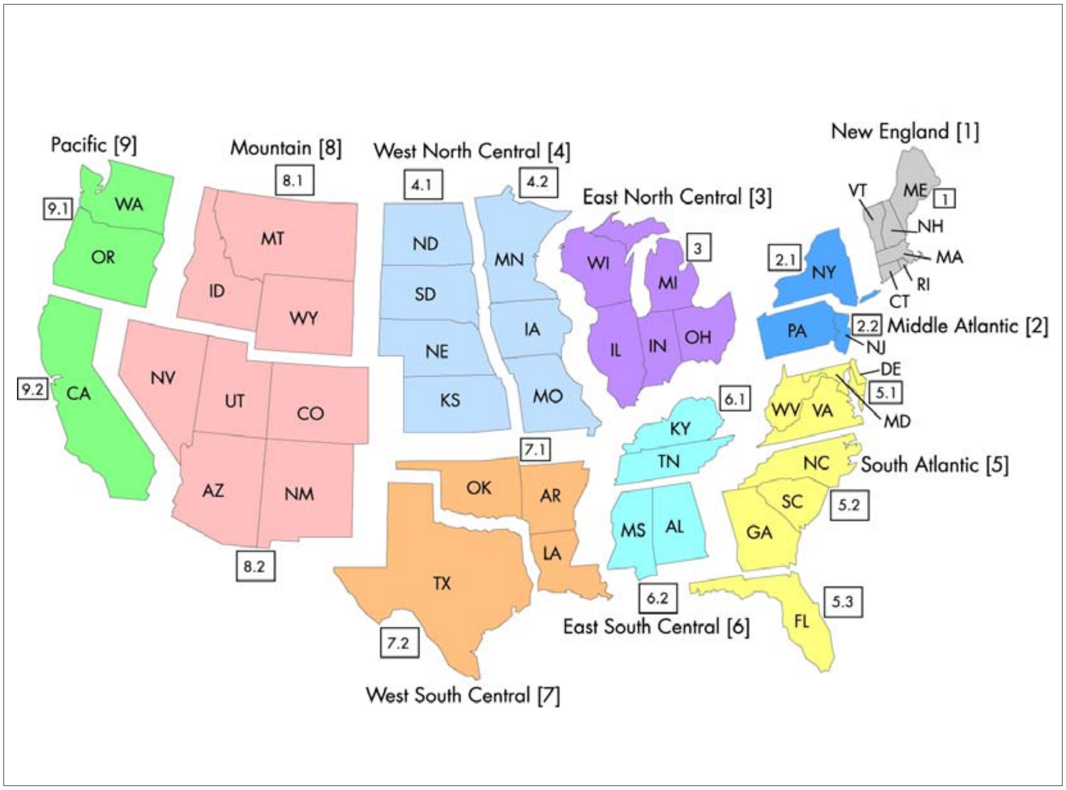

Figure 8.3.1 Map Showing the Division of the Continental United States into 17 Subdivisions

Representativeness of the Sample. For this rulemaking, the Department defined the representativeness of the sample by the percentage of the total number of C&I customers who were covered. It is relatively easy to get good representation for IOUs, because in most regions there are a few large companies serving many customers. It is more difficult to represent the publicly owned companies, as these tend to be much smaller; to obtain the same level of customer representation, DOE would need to include many more utilities. The sampled utilities serve 60 percent of the C&I customers of private utilities, and 14.4 percent of C&I customers for public utilities. The combined total for the U.S. is 48.5 percent of all C&I customers. Table 8.3.7 gives the percentage of customers by subdivision, broken down by ownership type.

Table 8.3.7 Percentage of All Commercial and Industrial Customers, by Subdivision, in the Utility Sample

Subdivision	Census Division	Region	Public Customers in Sample %	Private Customers in Sample %	Fraction of Total Customers in Sample %	Number of Customers in Sample
1	New England	New England	3.7	43.9	40.3	310,505
2.1	Middle Atlantic	New York	88.2	72.4	74.7	671,407
2.2	Middle Atlantic	PA, NJ	7.9	50.6	49.4	504,466
3	East North Central	WI,IL,IN,OH,MI	8.5	43.5	39.1	831,124
4.1	West North Central	MN, IA, MO	5.4	27.0	12.4	44,823
4.2	West North Central	ND,SD,NE,KS	9.8	59.0	46.5	387,603
5.1	South Atlantic	DE,MD,VA,WV	13.4	72.9	67.5	552,058
5.2	South Atlantic	NC,SC,GA	11.8	88.9	64.3	778,500
5.3	South Atlantic	Florida	15.1	72.0	58.4	530,513
6.1	East South Central	KY,TN	11.5	47.2	20.6	128,694
6.2	East South Central	MS,AL	9.9	68.5	42.9	217,970
7.1	West South Central	OK,AR,LA	3.5	60.4	44.1	265,412
7.2	West South Central	Texas	18.2	23.8	22.2	272,077
8.1	Mountain	MT,ID,WY	10.5	52.2	39.6	70,323
8.2	Mountain	NV,UT,CO,AZ,NM	5.9	71.8	46.2	310,765
9.1	Pacific	WA,OR	16.5	47.9	38.1	243,271
9.2	Pacific	California	20.3	97.4	75.8	1,050,862
	National Sample	USA	14.4	60.0	48.5	7,170,373

The ratio of total revenues to total energy sales—which reflects, on an average basis, the amount of money collected for each kWh sold—also varies significantly between utilities and across different regions. Figure 8.3.2 illustrates the degree of variation. The figure plots the customer-weighted average of utility revenues divided by sales (in units of $/kWh) within each subdivision. The vertical bars show the average value, plus or minus one standard deviation, for all the utilities in the EIA data. The points show the customer-weighted average revenues divided by sales for the sampled utilities only. There is a large spread in the EIA data, and sample averages are within this range.

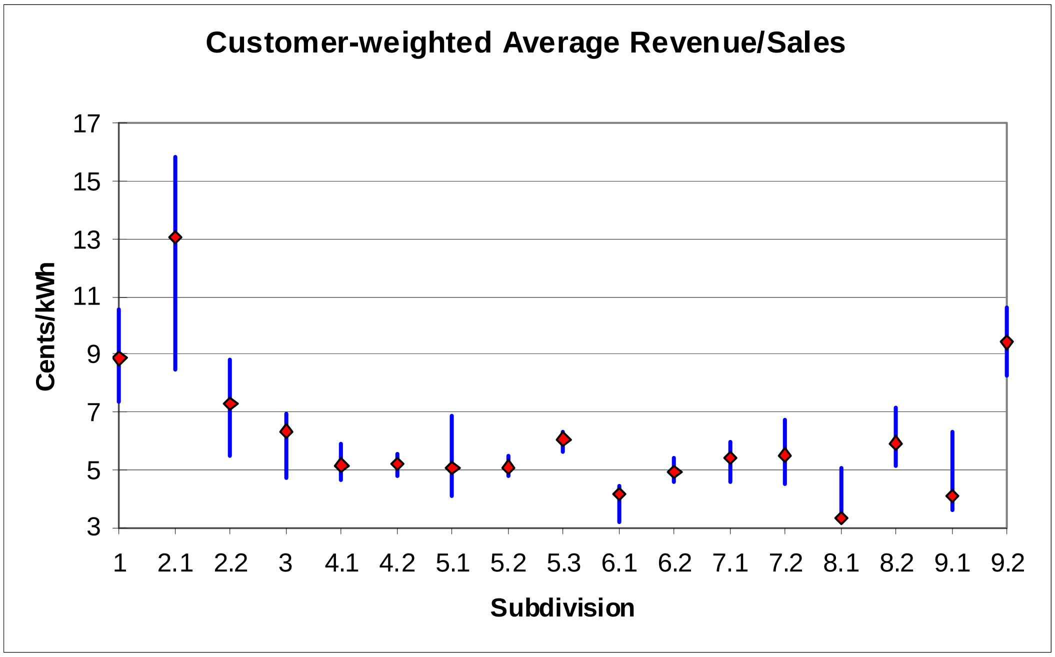

Figure 8.3.2 Customer-Weighted Average per kWh Revenue

Utility Weights. The way in which the Department assigned weights to the utilities depended on the application. As will be discussed in more detail below, the marginal rate seen by a particular customer depends both on the tariff and on that customer's energy use characteristics.

For this case, the appropriate weight for the utility is the number of customers it has divided by the number of customers in the subdivision. The weights for all the utilities in a given subdivision will then add up to one. Because the level of customer representation for public utilities is much less than for private ones, the Department included an additional factor to account for the difference so that the total weight of the sample's public utilities equals the fraction of public customers in that subdivision.

The weight for utility *k* is:

$$Weight(k,own\_type) = (\ n(k,own\_type)/n(own\_type)\ ) \times (\ N(own\_type)/N), \qquad \textbf{Eq. 8.4}$$

where *own_type* = *pub* (public) or *priv* (private). By definition,

$$\sum(own\_type)\sum(k)\ Weight(k,own\_type) = 1. \qquad \textbf{Eq. 8.5}$$

where:

n(k,pub)	=	number of customers served by publicly owned sample utility *k*,
n(k,priv)	=	number of customers served by privately owned sample utility *k*,
n(pub)	=	*sum(k) n(k,pub)* = total customers served by publicly owned sample utilities,
n(priv)	=	*sum(k) n(k,priv)* = total customers served by privately owned sample utilities,
N(pub)	=	total customers served by all publicly owned utilities in the subdivision,
N(priv)	=	total customers served by all privately owned utilities in the subdivision, and
N	=	*N(pub)* + *N(priv)* = total customers in the subdivision.

8.3.5.3 Data Collection and Modeling

This section briefly describes the data collection method, the selection of tariffs for a given utility, and how DOE modeled the tariffs.

Web Search. The Department collected the vast majority of the tariff documents directly from utility web sites. Almost every privately owned utility in the sample makes its whole tariff structure available on the web, although not always in easily readable form. In many cases, the full tariff, as approved by the relevant State public utility commission, is published and the actual customer rates have to be tracked down within this document. Many public utilities also put their rate information on the web. In cases where web documents were not available, the Department contacted the utilities directly. The list of utilities in Appendix 8C also includes a uniform resource locator (URL) for each company.

Selection of Tariffs for Each Utility. Utility companies have many tariffs, separated into residential, non-residential, and special-use—such as public street-lighting or agricultural. For the non-residential category, some utilities use the commercial-industrial distinction, but many do not. Therefore, in its tariff database, the Department combined these into one customer category. The goal in collecting the tariffs was to cover the full range of C&I customer types for each utility. In most cases, the Department assigned customers to a specific tariff based on their peak demand over the previous 12 months. In a few cases, the assignment was based on the maximum monthly electricity consumption. Customers are not generally moved from one tariff to another.

Most utilities offer only one tariff for each customer size. Some of the larger utilities offer optional time-of-use (TOU) or real-time pricing (RTP) tariffs. Occasionally, utilities will offer different tariffs for different business types. In all of the cases checked, although the tariffs had different names, the rates were in fact the same. Some utilities do not specify rates for very large customers whose peak demand is on the order of thousands of kWs; instead they negotiate them on a case-by-case basis. For the LCC calculation, the Department used only tariffs that depend on usage and demand data (not TOU nor RTP tariffs), because the energy consumption data used included only monthly demand and usage.

The Department's sampling strategy was to take the default tariff for each customer class. The Department excluded "closed" tariffs; these are tariffs that are being phased out by the utility and so are not available to new customers. This suggests that such tariffs do not reflect rates that will be seen by the majority of customers in the future.

Utilities do not generally make information available on how many customers are on each tariff; however, this information is not actually needed for the LCC. Instead, what is important to know is the relative numbers of customers who use the distribution transformer equipment covered by the standard who are on different tariffs. The CBECS data on the building weights define the relative proportion of customers of different sizes (here size refers to the customer's peak load), and the building monthly load data provide the annual peak load—which DOE used to assign a customer to a tariff.

The Tariff Model. To calculate a customer's electricity bill requires two sets of inputs: the rates charged as defined by the tariff, and information on the customer's energy use. The customer data consist of the billing demand and total energy consumption for the current billing period. In its analysis, the Department assumed the billing period to be one calendar month. The billing demand is the customer's peak demand over the billing month. While the formulae determining the actual bill can be quite complex, they are based on three types of charges: fixed, energy, and demand. Fixed charges are those paid each month regardless of the level of energy use. They do not contribute to customer marginal rates and so do not have any impact on the operating cost savings used in the LCC. Energy charges are specified in units of ¢/kWh and depend on the customer's total energy consumption. Demand charges are specified in units of $/kW and depend on the customer's monthly billing demand. For most of the utilities in the sample, charges also vary seasonally.

Energy and demand charges are typically applied in blocks. This means that the customer pays one rate for energy use or demand up to a certain level, a second rate for usage up to the next level, etc. For example, in a tariff with three blocks, the energy charges may be 10¢/kWh for the first 200 kWh, then 8¢/kWh for the next 1,000 kWh, and 6¢/kWh for all remaining energy use. This is an example of declining block rates, where the energy charge decreases as the energy used increases. One may also see inclining block rates. As a variation on this scheme, the block limits may depend on the customer's energy consumption and demand.

As an example of one such tariff, Figure 8.3.3 shows a block-by-demand tariff, which is representative of about 20-30 percent of the utilities sampled. This figure is illustrative and does not reflect any particular utility. The first block has a rate of 10¢/kWh for the first 200 kWh of energy used. The second block rate is 6¢/kWh for energy consumption up to 100 times the billing demand. The multiplier 100 is a tariff component with units of kWh/kW, which defines the width of the second block. The third block rate is 3¢/kWh for all subsequent energy use. Besides increasing the complexity of the calculation of the customer bill, this type of variable block size introduces a dependence of the energy charges on the billing demand. Two cases in Figure 8.3.3 illustrate this: in each case, the overall energy use is 3,200 kWh, but the billing demand is different (20 kW versus 21 kW).

In Case 1, the customer energy use is 3200 kWh, and the monthly peak demand is 20 kW. The width of the second block is 100×20 = 2000 kWh. In dollars, the customer will pay: (0.10)×200 + (0.06)×2000 + (0.03)×1000 = 20 + 120 + 30 = 170.

In Case 2, the customer energy consumption is also 3200 kWh, but the demand is 21 kW. Now the length of the second block is 2100 kWh, so the bill is: (0.10)×200 + (0.06)×2100 + (0.03)×900 = 20 + 126 + 27 = 173.

Even though the tariff specifies only energy charges, a change in the customer demand of one kW has increased the bill by $3.00. This is because 100 kWh of consumption have been shifted from the third, less expensive, block to the second, more expensive, block. Note that increasing the demand while holding the energy consumption fixed lowers the customer load factor, and in this case increases the effective marginal rate. This is a generic observation of the sampled tariffs.

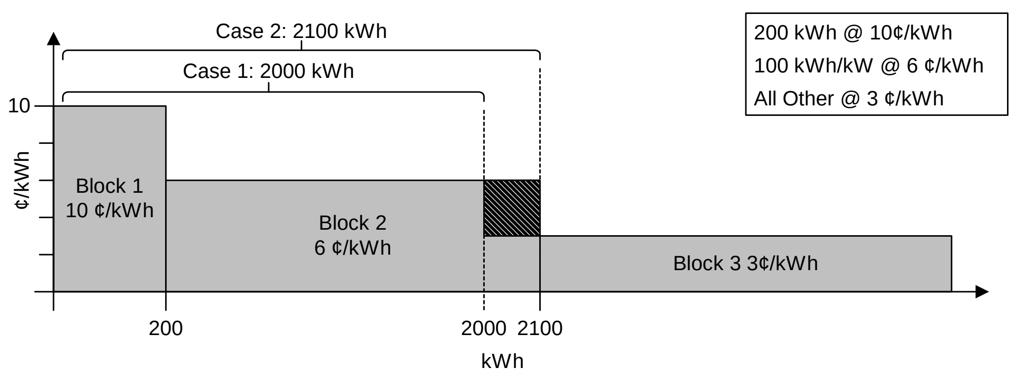

Figure 8.3.3 Effect of a Change in Customer Demand (Energy Consumption is Held Fixed) for a Block-By-Demand Tariff

The important point to take from this is that both demand and energy use contribute to the marginal rates seen by a customer, and often in ways that are not immediately obvious from reading the tariff. For the LCC, the energy cost savings due to the standard depend on the decrement to the total energy consumption, the decrement to the peak demand, and the ratio of the two. The effective marginal rate can vary substantially even for a set of customers on the same tariff.

Approximations Used in Modeling the Tariffs. In cases where the available information on the full set of charges seen by the customer is incomplete, the Department made the following approximations:

- *Riders and adders*: Some tariffs, particularly in deregulated areas, include additional charges as riders which may not be explicitly defined. The most significant are the fuel-cost-recovery adders. These are additional charges passed on to the customer when the utility must spend more than anticipated for fuel. These costs are included in the Department's analysis when they are given explicitly; however, they are sometimes represented as a formula based on the utility's expenditures and so cannot be modeled within the Department's framework. This results in a possible underestimation of costs for some customers.

- *Customer classes*: In a few cases, the utility specifies tariffs for "small" and "large" customers, without giving an explicit definition of these terms. In its review of the tariffs in the sample, the Department found that small customers typically have a peak demand on the order of 10 kW, medium customers have a demand on the order of 100 kW, and large customers have peak demands on the order of 1000 kW. The Department used a median value of 50 kW to separate customers into the "small" and "large" classes.

- *Ratchets*: Ratchets refer to situations where the billing demand for the current month is computed from a formula incorporating the monthly demand over the previous 12 months. For example, the billing demand may be set equal to either the current month's demand, or 80 percent of the maximum demand over the previous 12 months. A ratchet may also be seasonal. So, for example, the billing demand may be the greater of the current monthly demand or the peak demand in the most recent summer months. The Department did not include this type of rate formula in its tariff model. Instead, it assumed that the billing demand is the current monthly demand. The rationale behind ratchets is that demand charges are meant to cover capacity costs, and the actual capacity needed to serve a customer is better represented by their peak demand over a year rather than a month. New capacity is needed to serve a customer only when that customer contributes to the total system peak load, so one would expect that summer-peaking utilities would tend to implement ratchets that depend on summer demand. In these cases, the tariff model will underestimate the savings due to standards, since the billing demand decrement in each month will be somewhat less than the decrement for the summer months. The data collected on system loads show that all areas except the Northwest are summer-peaking in an average year. The southern states may have high loads during an especially cold winter, so these areas may implement ratchets that depend on the annual demand. In these cases, buildings with electric heat may have their peak demand occurring in the winter and, if the tariff includes a ratchet, the Department's model may over-estimate the savings due to standards.

Monthly Bill Calculations. The Department used the calendar month as the billing period. For each building, the Department used the peak demand and total energy consumption data from CBECS 1995 for 12 calendar months.[9] The Department kept the customer on the same tariff for both the base and the standards cases. The Department calculated the monthly bills, adding the distribution transformer losses for both the base and the standards cases. The difference between the annual bills for each standard level gave the associated operating cost savings. The Department calculated the customer marginal demand and energy prices as the net change in the total bill, divided by the net change in demand or energy, respectively.

To represent the full range of tariffs in the LCC spreadsheet, the Department created a Tariff Data Model (TDM). The TDM is a data structure used to store all of the tariff information in a format that is consistent across utilities. Briefly, the TDM divides each tariff into a collection of components. A component is defined by a set of parameters that include a rate, a range of values under which the rate applies, and indicator variables that specify if and when the rate should be applied. Using this component format, one can reconstruct the structure of any tariff from the set of components, and then apply the customer data used to determine whether conditions are met for a particular rate.

The TDM was the data structure used to store all of the tariff information. The objective of the TDM was to create a database structure that captured the complexity of a specific rate schedule (e.g., seasonal rates, variable block rates, mixtures of blocks, time-of-use tariffs) with sufficient accuracy to model any utility tariff

In principle, each tariff is simply a list of rates. However, a complete tariff is, in practice, often very complex. Typically, certain rules and conditions must be met for a particular rate to be applied. To capture this complexity, the TDM divides each tariff into a collection of components.

TDM Rates. Each tariff component has a rate parameter. The rate stored in the TDM is a dimensionless, real, numbered value. The "charge type" indicator specifies the units for a particular component.

TDM Indicators.

Charge Type. The charge-type indicator specifies the units for each component. The indicator is also used to keep track of charges as bills are calculated. There are three basic types of charges included in this sample: fixed charges, energy charges, and demand charges.

- Fixed charges ($/month) – These are typically monthly customer charges. Fixed rates are also used as minimum customer charges.

- Energy charges (¢/kWh) – These are the basic per-kWh charges associated with a tariff.

- Demand charges ($/kW) – These are the charges driven by peak consumption. Larger customers are typically subject to tariffs that incorporate demand charges.

Block Type. A block is the range in which a particular rate is applied. In general, these blocks are based on user consumption and demand. To determine these ranges, utilities use a variety of functions. In addition, a particular tariff may use different block functions for each block. However, at the component level, there is a small set of functions that can be used to set the limits of a range. In general, these limits are functions of kW of demand and kWh consumed (*Limit = f {kW, kWh}*). The block type indicates which limit function should be applied to each component. The Department modeled several functions.

- Fixed Block – This is the most common block type. The Department based the minimum and maximum limits on a predetermined *kWh* level.

- Block-By-Demand – This is also a common type, though less so then the fixed block. The maximum limit equals a *Demand Multiplier* × *User Demand*. In this case, the limit is not known until run time, when the user demand is known. (This type of block structure essentially incorporates a demand charge into an energy charge.) The minimum limit is set to the previous maximum.

- Mix Block Type 1 – The maximum limit is set by the maximum (*kWh, demand multiplier*×kW). The minimum limit is set to the previous maximum.

- Mix Block Type 2 – The maximum limit is set by the minimum (*kWh, demand multiplier*×kW). The minimum limit is set to the previous maximum.

- Mix Block Type 3 – The maximum limit is set by the sum (*kWh*, *demand multiplier*×kW). The minimum limit is set to the previous maximum.

TDM Ranges. The quantities that are used to determine limits are stored as ranges. The Department currently has ranges for seasonal limits and block limits.

- kWh Ranges – Minimum and maximum ranges for blocks are stored in units of kWh.

- kW Ranges – Minimum and maximum ranges for blocks are stored in dimensionless units. The block type indicator determines the unit for this range. Fixed blocks are in units of kW, other block types are the demand multiplier units, sometimes referenced by utilities as "Hours" or "kWh/kW."

- Month Range – Each utility defines the winter and summer months differently. The winter and summer start and end months are stored here.

- Season Type – The season type indicates in which season the component charge can be applied.

The Bill Calculator. The Bill Calculator (BC) is a set of accounting programs, implemented as functions, which can be accessed from within an Excel spreadsheet. These functions produce monthly bills for a user given the consumption, demand, and month. There are two functions of interest: *GetTariffs, and GetCharges*.

GetTariffs. For a given utility, a customer is typically assigned to one of several tariffs. *GetTariffs* determines the tariff to which the user is assigned given the peak consumption and peak demand levels.

GetCharges. GetCharges returns a monthly bill given the tariff, consumption, and demand. This is the core function that reconstructs a tariff from the TDM. The function reads data from the TDM and evaluates which charges should be applied. It tallies these charges and returns the monthly bill in dollars.

8.3.6 Load Growth Trends

The LCC analysis looks at a cross-section of transformers. The Department applied a load growth trend to each new transformer. Spreadsheet users have the choice of three scenarios using the Transformer Load Growth/Year drop-box on the "Summary" worksheet. The three scenarios for load growth are: no growth, one percent-per-year growth, and two percent-per-year growth. The Department used as the default scenario a one percent-per-year load growth for liquid-immersed transformers, i.e., a medium rate, as identified in the *Determination Analysis of Energy Conservation Standards for Distribution Transformers*, Report ORNL-6847.[11] The one-percent annual load growth trend from ORNL-6847 is consistent with the average electricity use growth per customer during the 1990s, as determined by EIA. The Department applied a one percent-per-year load growth trend to each new liquid-immersed transformer beginning in 2010, the expected effective date of the standard (see section 8.3.9). For dry-type transformers, installation of new circuits and transformers often accompanies new demand. The Department therefore expects load growth for dry-type transformer to be lower than for liquid-immersed transformers. For dry-type transformers, the Department used the no-growth scenario.

Figure 8.3.4 shows the cumulative growth for the default scenario of one percent-per-year load growth that the Department used for liquid-immersed transformers.

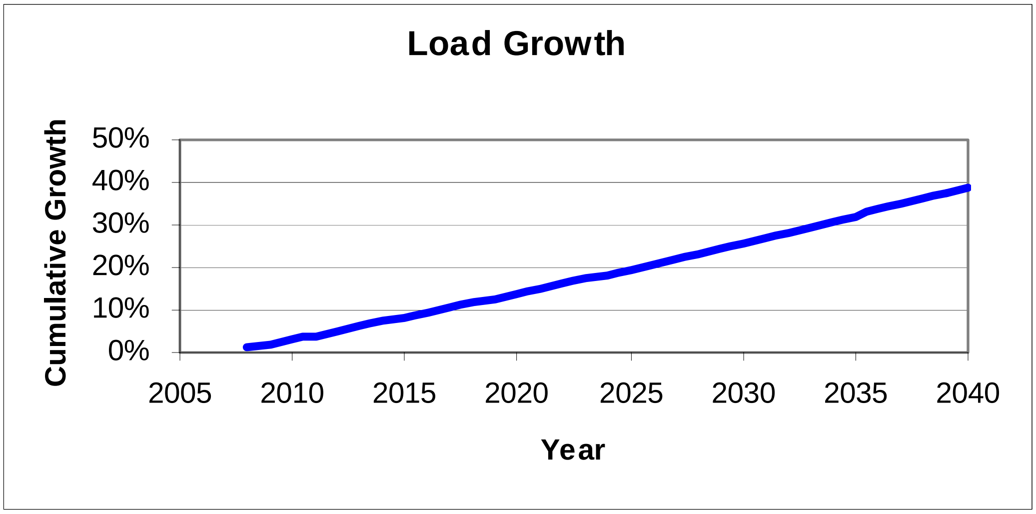

Figure 8.3.4 Cumulative Load Growth at One Percent per Year

8.3.7 Electricity Cost and Price Trends

For the relative change in electricity cost and prices for future years, the Department used the price trends from three *AEO2005* forecast scenarios from EIA.[4] LCC spreadsheet users have the choice of these three scenarios:

1. *AEO2005* Low Growth scenario,
2. *AEO2005* Reference scenario,
3. *AEO2005* High Growth scenario,
4. Constant Real Prices

Figure 8.3.5 shows the trends for the three *AEO2005* price projections. Because *AEO2005* does not forecast beyond 2025, the Department extrapolated the values in later years (i.e., after 2025) from their relative sources. To arrive at values for these later years, the Department used the price trend of the forecast from 2015 to 2025 to establish prices in the years 2026 to 2035. This method of extrapolation is in line with methods currently used by the EIA to forecast fuel prices for the Federal Energy Management Program (FEMP).

The default electricity price trend scenario that DOE used in the LCC analysis is the trend from the *AEO2005* Reference case. Spreadsheets used in calculating the LCC have the capability to analyze the other electricity price trend scenarios, namely the *AEO2005* High and Low Growth price trends.

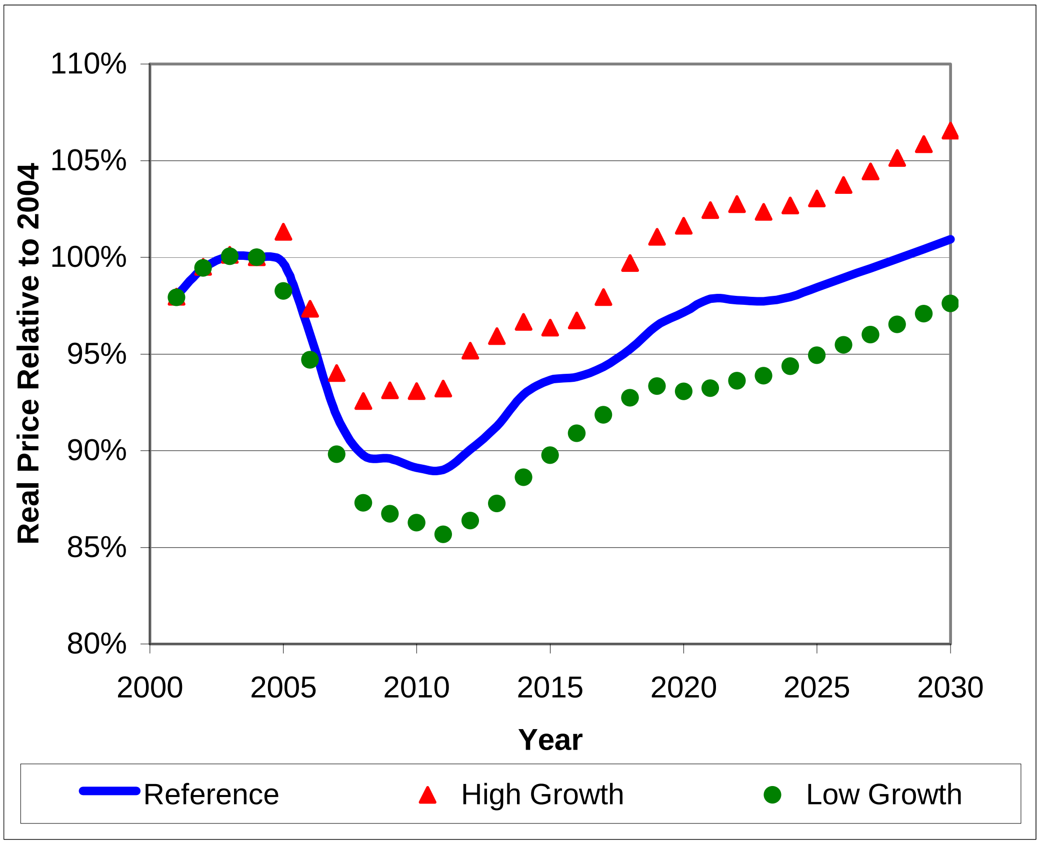

Figure 8.3.5 Electricity Price Scenarios

8.3.8 Discount Rate

The discount rate is the rate at which future expenditures are discounted to estimate their present value. The Department derived the discount rates selected for the transformer LCC analysis from estimates of the cost of capital for companies that purchase transformers. Following financial theory, the cost of capital can be interpreted in three ways: 1) it is the discount rate that should be used to reduce the future value of cash flows to be derived from a typical company project or investment; 2) it is the economic cost to the firm of attracting and retaining capital in a competitive environment; and 3) it is the return that investors require from their investment in a firm's debt or equity.[12] The Department primarily used the first interpretation. Most companies use both debt and equity capital to fund investments; for most companies, therefore, the cost of capital is the weighted average of the cost to the firm of equity and debt financing.[13]

The Department estimated the cost of equity financing using the Capital Asset Pricing Model (CAPM). The CAPM, among the most widely used models to estimate the cost of equity financing, assumes that the cost of equity is proportional to the amount of systematic risk associated with a firm. For example, the cost of equity financing tends to be high when a firm faces a large degree of systematic risk, and the cost tends to be low when the firm faces a small degree of systematic risk.

The degree of systematic risk facing a firm and the subsequent cost of equity financing are determined by several variables, including the risk coefficient of a firm (beta, or *B*), the expected return on risk-free assets (R_f), and the additional return expected on assets facing average market risk (which is known as the equity risk premium, or *ERP*). The beta indicates the degree of risk associated with a given firm, relative to the level of risk (or price variability) in the overall stock market. Betas usually vary between 0.5 and 2.0. A firm with a beta of 0.5 faces half the risk of other stocks in the market; a firm with a beta of 2.0 faces twice the overall stock market risk.

Following this approach, the cost of equity financing for a particular company is given by the equation:

$$k_e = R_f + (B \times ERP) \qquad \textbf{Eq. 8.6}$$

where:

k_e	=	the cost of equity for a company,
R_f	=	the expected return of the risk-free asset,
B	=	the beta of the company stock, and
ERP	=	the expected equity risk premium, or the amount by which investors expect the future return on equities to exceed that on the riskless asset.

The cost of debt financing (k_d) is the yield or interest rate paid on money borrowed by a company (raised, for example, by selling bonds). As defined here, the cost of debt includes compensation for default risk and excludes deductions for taxes.

The Department estimated the cost of debt for companies by adding a risk adjustment factor to the current yield on long-term corporate bonds (the risk-free rate). This procedure is used to estimate current (and future) company costs to obtain debt financing. The adjustment factor is based on indicators of company risk, such as credit rating or variability of stock returns.

The discount rate of companies is the weighted average cost of debt and equity financing, less expected inflation. The Department estimated the discount rate using the equation:

$$k = (k_e \times w_e) + (k_d \times w_d) \quad \textbf{Eq. 8.7}$$

where:

k	=	the (nominal) cost of capital,
k_e and k_d	=	the expected rates of return on equity and debt, respectively, and
w_e and w_d	=	the proportion of equity and debt financing, respectively.

The real discount rate deducts expected inflation from the nominal rate.

The expected return on risk-free assets, or the risk-free rate, is defined by the current yield on long-term government bonds.[14] The *ERP* represents the difference between the expected (average) stock market return and the risk-free rate. As shown in Table 8.3.8, the Department used an *ERP* estimate of 5.5 percent, which was taken from the Damodaran Online site (a private website associated with New York University's Stern School of Business, that aggregates information on corporate finance, investment, and valuation).[15]

The Department calculated an expected inflation of 2.3 percent from the average of the last five quarters' change in GDP prices.[16] The Department obtained the cost of debt, percent debt financing, and systematic firm risk from information provided at the Damodaran Online website.[a] Table 8.3.8 shows average values across all private companies. However, the cost of debt, percent debt financing, and systematic firm risk vary by sector. For example, average systematic firm risk of all private firms in the industrial sector is close to 1.0, while systematic firm risk in the utility sector averages close to 0.6.

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[a] The Department estimated percent debt for firms in the property-owning category using data from Bloomberg Professional.[17] The Department took the cost of debt for publicly owned utilities from FERC Form 1 filings.[6]

Table 8.3.8 Variables Used to Estimate Company Discount Rates

Variable	Symbol	Average Value	Source
Risk-free asset return	R_f	5.5%	Bloomberg Professional[17]
Equity risk premium	*ERP*	5.5%	Damodaran Online[15]
Expected inflation	r	2.3%	U.S. Bureau of Economic Analysis [16]
Cost of debt (after tax)	k_d	9.0%	Damodaran Online; FERC Form 1[6]
Percent debt financing	w_d	27%	Damodaran Online
Systematic firm risk	B	0.99	Damodaran Online

Transformers are purchased and owned by electric utilities (publicly and investor-owned), commercial and industrial companies, the owners of commercial buildings, (property owners), and the government. Table 8.3.9 shows the typical owners of transformer, grouped by transformer type owned (represented by the design lines DOE used in the engineering analysis). The Department used a sample of 4,294 companies drawn from these owner categories to represent transformer purchasers. It took the sample from the list of companies included in the Value Line investment survey[18] and listed on the Damodaran Online website. The Department obtained the cost of debt, the firm beta, the percent of debt and equity financing, the risk-free return, and the equity risk premium from Damodaran Online.

The Department estimated the cost of debt financing for these companies from the long-term government bond rate and the standard deviation of the stock price.[15] Publicly owned utilities, including municipals and cooperatives, do not issue stock and tend to be financed with debt. The Department obtained the cost of debt for these companies from information provided in FERC Form 1 filings. Finally, for government office-type owners the discount rate represents an average of the Federal rate and the State and local bond rate. The Department drew the Federal rate directly from the U.S. Office of Management and Budget discount rate for investments in government building energy efficiency.[19] The Department estimated the State and local discount rate from the interest rate on State and local bonds between 1977 and 2001.[20] The Department used this information to estimate the weighted-average cost of capital for the sample of companies included in the commercial property owner, commercial and industrial company, and utility database.

Table 8.3.9 Typical Owners of Different Types of Transformers

Design Line	Typical Ownership Categories
1, 2, 3, 4	Electric utilities, both publicly owned and investor-owned
5	Electric utilities, commercial property owners, commercial and industrial companies, government offices
6, 7, 8, 9, 10, 11, 12, 13	Commercial property owners, commercial and industrial companies, government offices

As previously mentioned, the cost of capital may be viewed as the discount rate that should be used to reduce the future value of typical company project cash flows. It is a nominal discount rate, since anticipated future inflation is included in both stock and bond expected returns. Deducting expected inflation from the cost of capital provides estimates of the real discount rate by ownership category (see Table 8.3.10). The mean real discount rate for these companies varies between 3.3 percent (government offices) and 7.5 percent (industrial companies).

Table 8.3.10 Real Discount Rates by Transformer Ownership Category

Ownership Category	**SIC Codes**	**Mean Real Discount Rate %**	**Standard Deviation %**	**Number of Observations**
Industrial Companies	1 - 4	7.5	3.2	2409
Commercial Companies	5 - 8	7.3	4.7	1773
Commercial Property Owners	6720	4.5	0.9	8
Utilities, Investor-Owned	49	4.2	1.5	63
Utilities, Publicly Owned	n/a	4.3	1.1	16
Government Offices	n/a	3.3	2.1	25

Source: Lawrence Berkeley National Laboratory (LBNL) calculations based on firms sampled from the Damodaran Online website.

Because investor-owned utilities purchase the bulk of many transformer design lines evaluated here, the discount rates calculated for that sector (see Table 8.3.10) are particularly important. The Department estimated that the average investor-owned utility real discount rate is 4.2 percent. The 4.2 percent figure is an after-tax discount rate, representing the return required by such utilities to attract financing. Private financial data companies, including Ibbotson Associates and Bloomberg Professional, offer similar estimates. The Bloomberg

Professional online service estimates the cost of investor-owned utility capital to be 4.4 percent.[a] Ibbotson Associates estimates the cost of capital in this sector (SIC 49), after deducting 2.3 percent inflation, to be 5.0 percent.[21]

The Department's approach for estimating the cost of capital provides a measure of the discount rate spread as well as the average discount rate. The Department inferred the discount rate spread by ownership category from the standard deviation, which ranges between 0.9 percent and 4.7 percent (Table 8.3.10). Publicly owned utility and property owner discount rates are narrowly concentrated around their mean value. By contrast, commercial and industrial company discount rates are dispersed across a broader range.

Different combinations of commercial property owners and commercial, industrial, and utility buyers purchase the different transformer design lines included in the engineering analysis (Chapter 5). Accordingly, the Department constructed the discount rates associated with any given design line from different combinations of commercial property owner, commercial, industrial, and utility discount rates. For example, transformer design line 6 is purchased by commercial property owners, commercial and industrial companies, and the government. Roughly 19 percent of customers are commercial property owners, 19 percent are industrial companies, 54 percent are commercial companies, and 7.9 percent are government offices (Table 8.3.11).[22]

The Department estimated discount rate distributions for the different design lines as a weighted average of the distributions for the different ownership types.

[a] This is the average cost of capital, after deducting 2.3 percent inflation, for the set of investor-owned utilities sampled in this analysis. The Department obtained this estimate from the Bloomberg Professional service, during December, 2001.[17]

Table 8.3.11 Transformer Ownership by Design Line

Transformer Design Line	Property Owners %	Industrial Companies %	Commercial Companies %	Investor-Owned Utilities %	Publicly Owned Utilities %	Government Offices %
1	0.4	0.5	0.9	72.0	26.0	0.2
2	0.4	0.5	0.9	72.0	26.0	0.2
3	2.1	2.4	4.5	80.0	10.0	1.0
4	0.4	0.5	0.9	72.0	26.0	0.2
5	9.5	9.5	27.0	35.0	15.0	4.0
6	19.0	19.0	54.0	0	0	7.9
7	19.0	19.0	54.0	0	0	7.9
8	19.0	19.0	54.0	0	0	7.9
9	19.0	19.0	54.0	0	0	7.9
10	19.0	19.0	54.0	0	0	7.9
11	19.0	19.0	54.0	0	0	7.9
12	19.0	19.0	54.0	0	0	7.9
13	19.0	19.0	54.0	0	0	7.9

Source: DOE contractors.

8.3.9 Effective Date of Standard

The effective date of the new energy-efficiency standards for distribution transformers is three years after the Department issues the final rule. The Department assumed that it will issue the final rule in 2007 in which case the new standards would take effect in 2010. The Department calculated the LCC for all users as if each new distribution transformer purchase occurs in the year the standards take effect. It based the cost of the equipment on that year; however, as stated above, the Department expresses all dollar values in 2004$.

8.3.10 Transformer Service Life

The Department defined distribution transformer service life as the age at which the transformer retires from service. The Department assumed, based on ORNL-6847, *Determination Analysis of Energy Conservation Standards for Distribution Transformers*,[11] that the average life of distribution transformers is 32 years. This lifetime assumption includes a constant failure rate of 0.5 percent/year due to lightning and other random failures unrelated to transformer age, and an additional corrosive failure rate of 0.5 percent/year at year 15 and beyond. The Department adjusted the retirement distribution to maintain an average life of 32 years.

8.3.11 Maintenance Costs

The maintenance cost is the cost to the consumer of maintaining equipment operation. The maintenance cost is not the cost associated with the replacement or repair of components that have failed. Rather, the maintenance cost is associated with general maintenance. The Department assumed that the cost for general maintenance will not change with increased efficiency. In practice, there is little scheduled maintenance for transformers. Maintenance consists of brief annual checks for dust buildup, vermin infestation, and accident or lightning damage.

8.3.12 Power Factor

The power factor is the real power divided by the apparent power. Real power is the time average of the instantaneous product of voltage and current. Apparent power is the product of the RMS voltage times the RMS current. Transformer efficiency specifications, such as NEMA's TP 1-2002, assume a power factor of 1.0.[1] Therefore, the Department used a power factor of 1.0, both in calculating the efficiency levels in the engineering analysis and when preparing candidate standard levels for the Notice of Proposed Rulemaking (NOPR).

However, in real-world installations, the loads experienced by distribution transformers are likely to have power factors of less than 1.0. Because the LCC analysis models transformers that are installed and operating in the field, DOE created the LCC spreadsheet with an adjustable power factor, enabling the LCC to run at lower power factor values. In the absence of any specific data or guidance on the appropriate power factor, the Department used 1.0 for this LCC analysis.

8.3.13 Default Scenario

The Department developed distinct scenarios for several key input parameters. It describes these distinct scenarios as low, medium, and high. For each of the key inputs, the Department chose the medium designation as the default scenario. The overall default scenario used in the LCC analysis has the following values:

- transformer load growth/year: medium (1 percent) for liquid-immersed, low (0 percent) for dry-type
- transformer loading (relative to current estimate): medium (0 percent)

- electricity prices (relative to current estimate): medium (0 percent)
- transformer customer A's and B's: medium
- future energy price trend: *AEO2005* reference

Other scenarios can readily be used to explore sensitivities to variations of these key variables.

8.4 LIFE-CYCLE COST RESULTS

This section presents LCC results for the efficiency improvement levels evaluated for all 13 design lines. Table 8.4.1 provides an overview of the six candidate standard levels the Department evaluated for each of the 13 design lines examined. The lowest efficiency candidate standard level is NEMA's TP 1-2002 and the highest is the most efficient design identified in the engineering analysis. The remaining four efficiency levels are spread between these two bounds. The Department expresses all the candidate standard levels in terms of efficiency, with no explicit or implicit technology assumed. The column labeled "TP 1+" shows by how much the given standard level exceeds TP 1-2002. The Department based the results presented in this section on the inputs described in section 8.3.

Table 8.4.1 Candidate Standard Levels Evaluated For Each Design Line

Design Line	Level 1 TP 1		Level 2		Level 3		Level 4		Level 5		Level 6	
	TP 1		1/3 of Diff. between TP 1 and Min LCC		2/3 of Diff. between TP 1 and Min LCC		Min LCC		Max Energy Savings with No Change in LCC		Max Energy Savings	
	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %
1	0.00	98.9	0.14	99.04	0.29	99.19	0.43	99.33	0.59	99.49	0.69	99.59
2	0.00	98.7	0.03	98.73	0.06	98.76	0.09	98.79	0.26	98.96	0.76	99.46
3	0.00	99.3	0.08	99.38	0.16	99.46	0.24	99.54	0.44	99.74	0.45	99.75
4	0.00	98.9	0.18	99.08	0.36	99.26	0.55	99.45	0.68	99.58	0.71	99.61
5	0.00	99.3	0.06	99.36	0.12	99.42	0.17	99.47	0.41	99.71	0.41	99.71
6	0.00	98.0	0.22	98.22	0.44	98.44	0.66	98.66	0.90	98.90	0.90	98.90
7	0.00	98.0	0.32	98.32	0.64	98.64	0.95	98.95	1.13	99.13	1.13	99.13
8	0.00	98.6	0.22	98.82	0.44	99.04	0.66	99.26	0.73	99.33	0.73	99.33
9	0.00	98.6	0.22	98.82	0.44	99.04	0.66	99.26	0.81	99.41	0.81	99.41
10	0.00	99.1	0.12	99.22	0.23	99.33	0.35	99.45	0.41	99.51	0.41	99.51
11	0.00	98.5	0.17	98.67	0.34	98.84	0.51	99.01	0.59	99.09	0.59	99.09
12	0.00	99.0	0.12	99.12	0.23	99.23	0.35	99.35	0.40	99.40	0.40	99.40
13	0.00	99.0	0.15	99.15	0.30	99.30	0.45	99.45	0.55	99.55	0.55	99.55

One of the primary impacts of an energy-efficiency standard is the change in the set of transformer designs available for purchase and their corresponding loss characteristics, i.e., load losses (LL) and no-load losses (NL). This impact is illustrated in the LL versus NL graph (fourth from right worksheet in the LCC spreadsheet). Figure 8.4.1 provides an illustration of the LL versus NL graph taken from the LCC spreadsheet for design line 1, using the TP 1-2002 standard level. Since each design line has a unique set of engineering constraints, the LL-versus-NL graph for each design will be different. This graph plots an example of a Crystal Ball LCC run (limited to 50 iterations for legibility in this graphic format). It shows different sets of designs by their load losses at rated load and their no-load losses. Potential designs are shown as both small dots and small squares. The standard level is illustrated by a thick line (those designs that satisfy the standard are to the left of this line). The selected designs not subject to standard constraints are plotted as triangles. The designs subject to standards constraints are plotted as dots. As the standard level increases, the thick line moves parallel to the left (to the area of the graph with lower losses), and so does the set of constrained designs. The standard level is selected with the corresponding pull-down menu on the "Summary" sheet. Some of the selected designs meeting the standard (especially those with higher load losses) are plotted to the right of the line. This is because the efficiency rating and design assumptions use different percentage loading definitions. The efficiency level rating is defined at 50 percent (liquid-immersed and medium-voltage dry-type) or 35 percent (low-voltage dry-type) loading, while the load and no-load losses for the design assumptions are defined by nameplate loading (100 percent). For those designs with higher load losses, the heating from losses causes the actual efficiency to drop, shifting the design to the right.

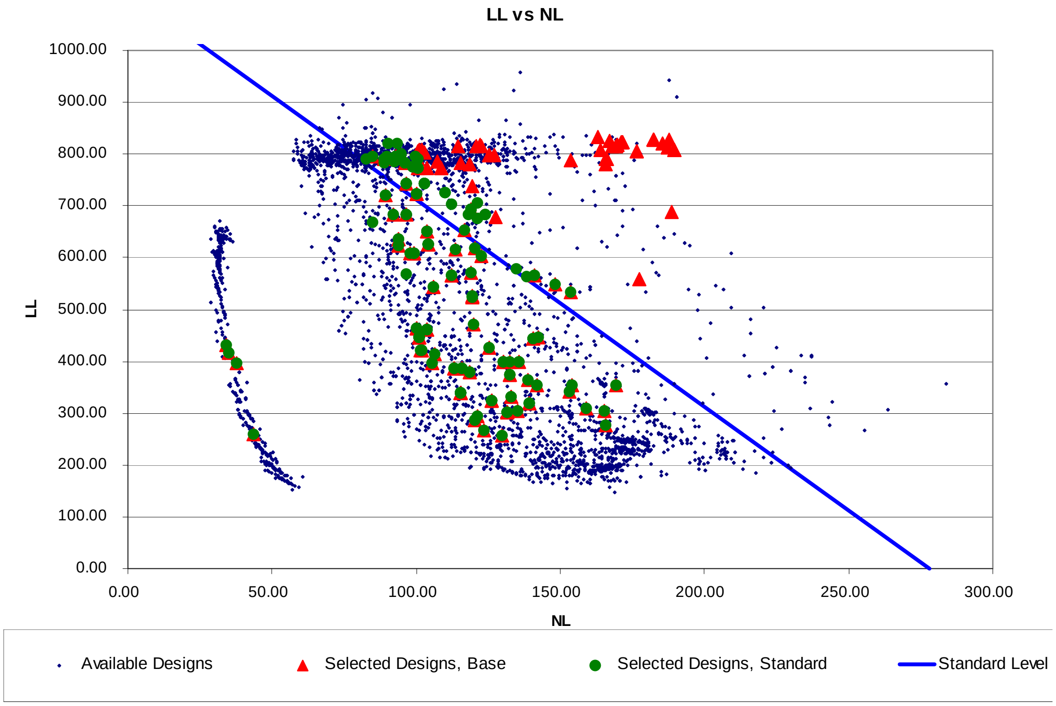

Figure 8.4.1 Design Load Losses (LL) versus No-load Losses (NL) for TP 1-2002, Design Line 1

The following 13 tables present the summary results from the Department's LCC analysis. For each evaluated design line and each candidate standard level, the Department presents the percent efficiency, the percent of evaluated transformer purchases that would experience positive LCC savings when subject to the candidate standard level, and the mean LCC savings. The Department presents these summary results for consideration; it has not selected any specific candidate standard level for any design line. Graphical representations of these results, which provide a clearer indication of the full distributions, are included in Appendix 8A.

8.4.1 Design Line 1 Results

Table 8.4.2 presents the summary of the LCC analysis for the representative unit from design line 1, a 50 kVA, liquid-immersed, single-phase, pad-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.97 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.56 percent, and the consumer equipment cost before installation was $1,382.00.

Table 8.4.2 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.90	99.04	99.19	99.33	99.49	99.59
Transformers having LCC Savings ≥0 (%)	95.1	83.4	47.2	72.3	42.1	9.5
Mean LCC Savings ($)	93	98	5	180	3	-688

8.4.2 Design Line 2 Results

Table 8.4.3 presents the summary of the LCC analysis for the representative unit from design line 2, a 25 kVA, liquid-immersed, single-phase, pole-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.74 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.23 percent, and the consumer equipment cost before installation was $737.00.

Table 8.4.3 Summary Life-Cycle Cost Results for Design Line 2 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.70	98.73	98.76	98.79	98.96	99.46
Transformers having LCC Savings ≥0 (%)	98.6	97.0	94.8	91.4	56.1	1.1
Mean LCC Savings ($)	69	70	72	71	7	-953

8.4.3 Design Line 3 Results

Table 8.4.4 presents the summary of the LCC analysis for the representative unit from design line 3, a 500 kVA, liquid-immersed, single-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.36 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 99.07 percent, and the consumer equipment cost before installation was $5,428.00.

Table 8.4.4 Summary Life-Cycle Cost Results for Design Line 3 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.30	99.38	99.46	99.54	99.74	99.75
Transformers having LCC Savings ≥0 (%)	99.8	98.6	93.9	60.1	33.7	29.2
Mean LCC Savings ($)	1,746	2,267	2,775	2,876	627	-410

8.4.4 Design Line 4 Results

Table 8.4.5 presents the summary of the LCC analysis for the representative unit from design line 4, a 150 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.91 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.42 percent, and the consumer equipment cost before installation was $3,335.00.

Table 8.4.5 Summary Life-Cycle Cost Results for Design Line 4 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.90	99.08	99.26	99.45	99.58	99.61
Transformers having LCC Savings ≥0 (%)	96.7	83.2	59.0	68.8	35.6	25.5
Mean LCC Savings ($)	556	629	450	767	56	-572

8.4.5 Design Line 5 Results

Table 8.4.6 presents the summary of the LCC analysis for the representative unit from design line 5, a 1500 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.36 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 99.13 percent, and the consumer equipment cost before installation was $11,931.00.

Table 8.4.6 Summary Life-Cycle Cost Results for Design Line 5 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.30	99.36	99.42	99.47	99.71	99.71
Transformers having LCC Savings ≥0 (%)	99.7	98.5	89.8	84.1	42.9	42.8
Mean LCC Savings ($)	3,957	5,463	6,504	7,089	4,431	3,902

8.4.6 Design Line 6 Results

Table 8.4.7 presents the summary of the LCC analysis for the representative unit from design line 6, a 25 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 95.56 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 94.98 percent, and the consumer equipment cost before installation was $646.00.

Table 8.4.7 Summary Life-Cycle Cost Results for Design Line 6 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.00	98.22	98.44	98.66	98.90	98.90
Transformers having LCC Savings ≥0 (%)	99.3	98.9	97.0	95.4	88.5	89.1
Mean LCC Savings ($)	1,758	2,026	2,148	2,168	1,987	2,030

8.4.7 Design Line 7 Results

Table 8.4.8 presents the summary of the LCC analysis for the representative unit from design line 7, a 75 kVA, low-voltage, dry-type, three-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 96.31 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 95.84 percent, and the consumer equipment cost before installation was $1,498.00

Table 8.4.8 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.00	98.32	98.64	98.95	99.13	99.13
Transformers having LCC Savings ≥0 (%)	99.6	99.2	98.6	96.0	90.7	90.5
Mean LCC Savings ($)	3,799	4,080	4,714	5,039	4,802	4,862

8.4.8 Design Line 8 Results

Table 8.4.9 presents the summary of the LCC analysis for the representative unit from design line 8, a 300 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.70 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 97.22 percent, and the consumer equipment cost before installation was $3,801.00.

Table 8.4.9 Summary Life-Cycle Cost Results for Design Line 8 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.60	98.82	99.04	99.26	99.33	99.33
Transformers having LCC Savings ≥0 (%)	99.1	98.5	98.1	91.9	88.1	88.7
Mean LCC Savings ($)	7,617	9,152	10,603	11,323	11,057	11,052

8.4.9 Design Line 9 Results

Table 8.4.10 presents the summary of the LCC analysis for the representative unit from design line 9, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV basic impulse insulation level (BIL). For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.77 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.41 percent, and the consumer equipment cost before installation was $7,510.00.

Table 8.4.10 Summary Life-Cycle Cost Results for Design Line 9 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.60	98.82	99.04	99.26	99.41	99.41
Transformers having LCC Savings ≥0 (%)	99.4	98.9	94.7	74.3	43.7	45.0
Mean LCC Savings ($)	988	1,968	3,103	3,532	1,181	1,274

8.4.10 Design Line 10 Results

Table 8.4.11 presents the summary of the LCC analysis for the representative unit from design line 10, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.17 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.79 percent, and the consumer equipment cost before installation was $33,584.00.

Table 8.4.11 Summary Life-Cycle Cost Results for Design Line 10 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.10	99.22	99.33	99.45	99.51	99.51
Transformers having LCC Savings ≥0 (%)	95.6	94.9	91.1	79.0	33.7	33.8
Mean LCC Savings ($)	4,041	5,227	6,818	7,699	1,279	1,124

8.4.11 Design Line 11 Results

Table 8.4.12 presents the summary of the LCC analysis for the representative unit from design line 11, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.42 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.05 percent, and the consumer equipment cost before installation was $10,945.00.

Table 8.4.12 Summary Life-Cycle Cost Results for Design Line 11 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.50	98.67	98.84	99.01	99.09	99.09
Transformers having LCC Savings ≥0 (%)	97.6	96.1	90.2	78.0	65.8	66.8
Mean LCC Savings ($)	2,491	3,621	4,313	4,845	4,186	4,289

8.4.12 Design Line 12 Results

Table 8.4.13 presents the summary of the LCC analysis for the representative unit from design line 12, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.18 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.81 percent, and the consumer equipment cost before installation was $33,590.00.

Table 8.4.13 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.00	99.12	99.23	99.35	99.40	99.40
Transformers having LCC Savings ≥0 (%)	98.6	98.5	94.2	81.8	29.4	29.9
Mean LCC Savings ($)	2,600	3,973	5,485	6,812	-650	-655

8.4.13 Design Line 13 Results

Table 8.4.14 presents the summary of the LCC analysis for the representative unit from design line 13, a 2000 kVA, medium-voltage, dry-type, three-phase transformer with a 125kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.26 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.97 percent, and the consumer equipment cost before installation was $41,873.00.

Table 8.4.14 Summary Life-Cycle Cost Results for Design Line 13 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.00	99.15	99.30	99.45	99.55	99.55
Transformers having LCC Savings ≥0 (%)	96.2	98.5	95.6	57.4	24.2	24.3
Mean LCC Savings ($)	662	3,125	5,430	6,435	-5,303	-5,218

8.5 LIFE-CYCLE COST SENSITIVITY ANALYSIS

The Department recognizes that there is always some uncertainty associated with engineering and economic analyses. To minimize that uncertainty, the Department strives to use the best techniques and the best data at its disposal. To cover the widest possible set of scenarios in this analysis, the Department used distributions of values for key inputs. For some variables, the Department went one step further by including in the analysis tool, i.e., the LCC spreadsheet, the ability to repeat the very same LCC analysis using values different from the default set used to produce the Department's results.

Detailed descriptions of all of the LCC input variables are included in the discussion of inputs in section 8.3, with additional information in Chapters 6 and 7. This section focuses on five key variables and the impact on the LCC results of assigning them a range of different values. The five variables and the location of their descriptive materials are as follows:

1. percentage of transformers purchased using A & B evaluation (see section 8.3.1);
2. transformer loading (see Chapter 6);
3. electricity price trends (see section 8.3.7);
4. load growth trends (see section 8.3.6); and
5. equipment price scenarios (see Appendix 5E).

This sensitivity analysis examines how sensitive the results are to changes in key DOE assumptions. For the NOPR, DOE conducted the sensitivity analysis on design lines 1, 7, and 12. This analysis treats each variable independently, i.e., default values remain in effect for all variables except the one being examined. Sensitivity results should always be compared to the default results. Each of the five variables has three values—low, medium, and high—that are described in more detail in the individual input variable sections.

The variable that characterizes the percentage of transformers purchased using A and B evaluation uses the same set of low and high values for both liquid-immersed and dry-type transformers. The low value represents a scenario where no transformer purchases are evaluated, i.e., a non-evaluating scenario. The high value represents a scenario where all transformer purchases are evaluated. The medium value for low-voltage dry-type transformers represents a scenario where 10 percent of purchases are evaluated. The medium value for small-capacity, medium-voltage, dry-type transformers represents a scenario where 50 percent of purchases are evaluated. The medium value for large-capacity, medium-voltage, dry-type transformers represents a scenario where 80 percent of purchases are evaluated. The medium value for liquid-immersed transformers represents a scenario where 75 percent of the purchases are evaluated.

For transformer loading, the medium scenario represents the output of the load simulation described in Chapter 6. The low scenario decreases the medium scenario load by 15 percent and the high scenario increases the medium scenario by 15 percent. For load growth, the low, medium, and high annual scenarios are zero percent, one percent, and two percent, respectively. Electricity price trends use the *AEO2005* low, reference, and high growth scenarios. For equipment price scenarios, the medium scenario represents the 5-year average material prices described in Appendix 5E. The high and low price scenarios are also described in Appendix 5E.

8.5.1 Design Line 1 Summary Sensitivity Results

The representative unit from design line 1 is a 50 kVA, liquid-immersed, single-phase, pad-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.97 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.56 percent, and the consumer equipment cost before installation was $1,382.00. Table 8.5.1 and Figure 8.5.1 illustrate the LCC sensitivity to changes in the five user-selectable variables. Each of the sensitivity runs for all the variables causes some change in the LCC results. However, for design line 1, only the change in percentage of transformers purchased using A & B evaluation results in significant changes in the results for all candidate standard levels examined. The Department found that the variable labeled *A & B Distribution* stands significantly apart from the other variables for most candidate standard levels. The reason that the A & B distribution is so important is that it describes whether or not the transformer purchasers place an economic value on losses even without a standard. If transformer purchasers already place an economic value on losses, then standards will have a small impact on purchase behavior, and the impact of a candidate standard level will be small. If no purchasers place an economic value on losses without a standard, then a standard can have a large beneficial impact from decreased energy costs. The A & B distribution options describe the full range of possible purchase behavior scenarios.

At the higher efficiency levels represented by candidate standard levels 4 through 6, equipment price has a significant impact. At level 6, equipment price shows the largest difference from the default assumptions, because of the limited material options available to produce transformers at that high efficiency. For this design line, the remaining sensitivities have increasing differences from the default assumptions as efficiency level increases, but are always significantly smaller than A & B evaluation and material price in difference from the default assumptions.

Table 8.5.1 Mean Life-Cycle Cost Savings ($), Summary for Design Line 1 Representative Unit

Scenario	Candidate Standard Level					
	1 (TP 1)	2	3	4	5	6
Baseline	93	98	5	180	3	-688
Non-Evaluating A & B Distribution	342	375	246	446	241	-457
High-Evaluating A & B Distribution	10	7	-72	90	-66	-754
Low Loading	84	76	-53	155	-62	-790
High Loading	101	130	73	213	87	-560
Low Electricity Price	77	73	-39	120	-87	-798
High Electricity Price	107	122	52	245	91	-575
Low Load Growth	86	65	-63	151	-79	-809
High Load Growth	100	112	32	192	36	-633
Low Equipment Price Scenario	96	109	65	278	164	-399
High Equipment Price Scenario	86	75	35	202	-56	-924

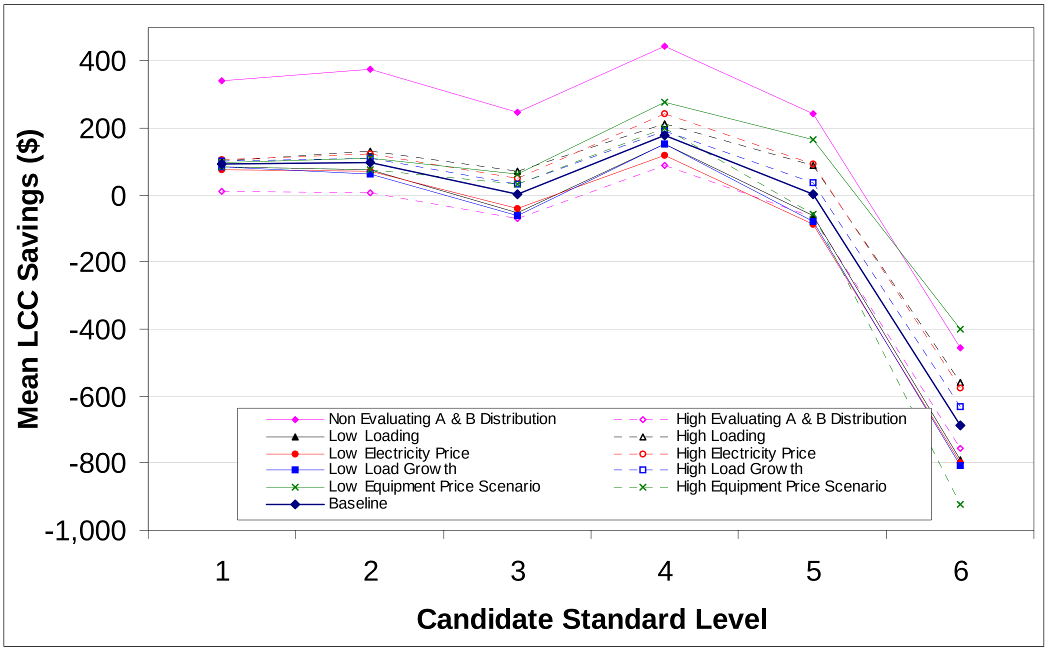

Figure 8.5.1 Design Line 1 Sensitivity Results by Candidate Standard Level

8.5.2 Design Line 7 Summary Sensitivity Results

The representative unit from design line 7 is a 75 kVA, low-voltage, dry-type, three-phase transformer with a 10kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 96.31 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 95.84 percent, and the consumer equipment cost before installation was $1,498.00. Table 8.5.2 and Figure 8.5.2 illustrate the LCC sensitivity to changes in the five user-selectable variables for design line 7. Each of the sensitivity runs for all the variables causes some change in the LCC results. The changes in results tend to increase with the efficiency of the candidate standard level. For design line 7, the change in percentage of transformers purchased using A & B evaluation results in significantly larger changes in the LCC savings, for all levels examined, than do the other variables. Figure 8.5.2 provides the clearest example of this outcome with high evaluation percentage standing by itself at the bottom of the graph. As with design line 1, this is because the purchase behavior described by A & B strongly affects how much energy is used when there is no standard, and thus affects the potential savings. The percentage of purchasers conducting A- and B-based evaluations in the high scenario for this dry-type design line is 100 percent compared to the default medium scenario of 10 percent conducting evaluations, so the difference is quite large and a significant difference in LCC savings should be expected. The extremely low LCC savings from the high A & B distribution case results from the fact that the Department assumes that most purchasers place an economic value on losses in that scenario even without standards. For most candidate standard levels, the variable labeled *A & B Distribution* stands significantly apart from the other variables.

The next most significant impact on LCC savings is from the projection of future electricity prices, which shows significant LCC impact for all levels examined. For the ranges examined, the Department found that changing transformer loading and load growth assumptions results in significant changes in LCC results only at the higher efficiency levels. In Figure 8.5.2, the increase in mean LCC savings occurs up to candidate standard level 4 and then falls for candidate standard levels 5 and 6.

Table 8.5.2 Mean Life-Cycle Cost Savings ($), Summary for Design Line 7 Representative Unit

Scenario	**Candidate Standard Level**					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Baseline	3,799	4,080	4,714	5,039	4,802	4,862
Non-Evaluating A & B Distribution	4,226	4,602	5,156	5,609	5,278	5,302
High-Evaluating A & B Distribution	17	108	272	531	211	212
Low Loading	3,768	4,078	4,470	4,681	4,250	4,279
High Loading	3,831	4,141	4,886	5,336	5,097	5,170
Low Electricity Price	3,167	3,449	3,887	4,191	3,854	3,808
High Electricity Price	4,386	4,754	5,442	5,969	5,687	5,789
Medium Load Growth	3,811	4,173	4,847	5,403	5,251	5,262
High Load Growth	3,772	4,161	4,925	5,528	5,467	5,354
Low Equipment Price Scenario	3,735	4,124	4,712	5,171	5,062	5,013
High Equipment Price Scenario	3,571	3,854	4,224	4,607	4,038	4,061

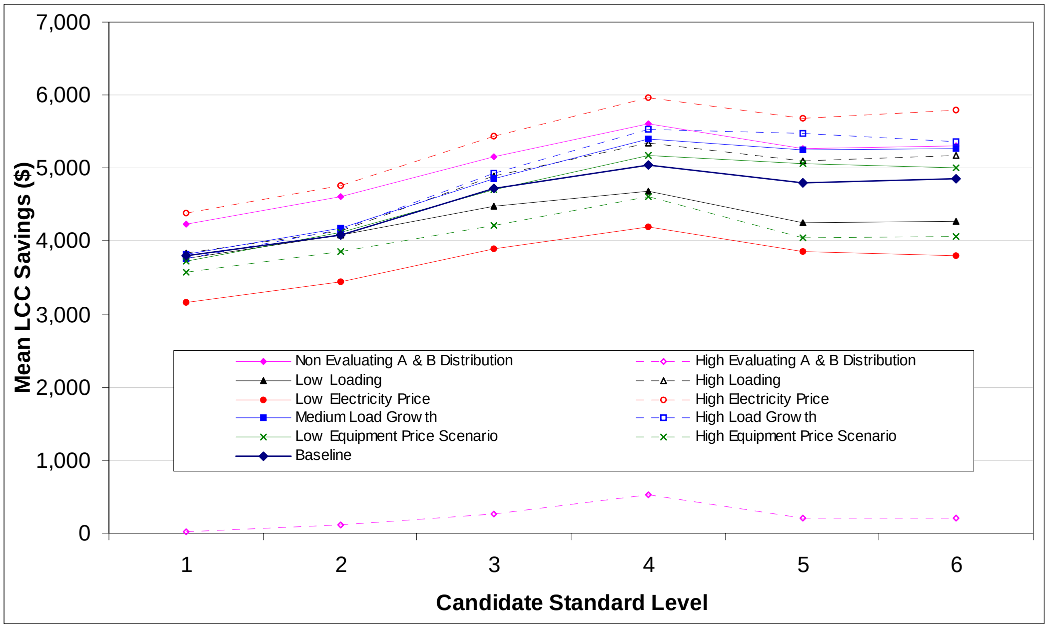

Figure 8.5.2 Design Line 7 Sensitivity Results by Candidate Standard Level

8.5.3 Design Line 12 Summary Sensitivity Results

The representative unit from design line 12 is a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.18 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.81 percent, and the consumer equipment cost before installation was $33,590.00. Table 8.5.3 and Figure 8.5.3 illustrate the LCC sensitivity to changes in the five user-selectable variables for design line 12. Each of the sensitivity runs for all the variables cause some change in the LCC results. The changes in results tend to increase with the efficiency of the candidate standard level. For design line 12, the change in percentage of transformers purchased using A & B evaluation results in significantly larger changes in the LCC savings than do the other variables for all but the highest two candidate standard levels examined. As with design line 1, this outcome occurs because the purchase behavior described by A & B evaluation strongly affects how much energy is used when there is no standard, and thus affects the potential savings. The high savings from the low A & B distribution case results from the fact that the Department assumes that few purchasers place an economic value on losses in that scenario without standards. For most candidate standard levels, the variable labeled *A & B Distribution* stands significantly apart from the other variables. LCC savings tend to increase as efficiency level increases up to candidate standard level 4 and drop off for levels 5 and 6. At the higher efficiency levels of 5 and 6, low loading, high material prices, low A & B evaluation, and high electricity prices all result in significant drops in LCC savings.

Table 8.5.3 Mean Life-Cycle Cost Savings ($), Summary for Design Line 12 Representative Unit

Scenario	Candidate Standard Level					
	1 (TP 1)	2	3	4	5	6
Baseline	2,600	3,973	5,485	6,812	-650	-655
Non-Evaluating A & B Distribution	11,033	15,868	19,944	22,607	15,289	15,436
High-Evaluating A & B Distribution	424	877	1,646	2,732	-4,641	-4,699
Low Loading	2,145	3,238	4,046	4,578	-5,234	-5,091
High Loading	2,713	4,481	6,051	8,125	1,947	1,790
Low Electricity Price	2,063	3,254	4,186	5,153	-3,705	-3,500
High Electricity Price	2,917	4,748	6,340	8,458	2,232	2,044
Medium Load Growth	2,783	4,370	6,270	8,598	2,642	2,386
High Load Growth	2,984	4,436	6,497	9,108	4,525	4,184
Low Equipment Price Scenario	2,496	3,725	4,993	6,410	1,319	1,596
High Equipment Price Scenario	2,534	4,279	5,906	7,091	-5,842	-5,797

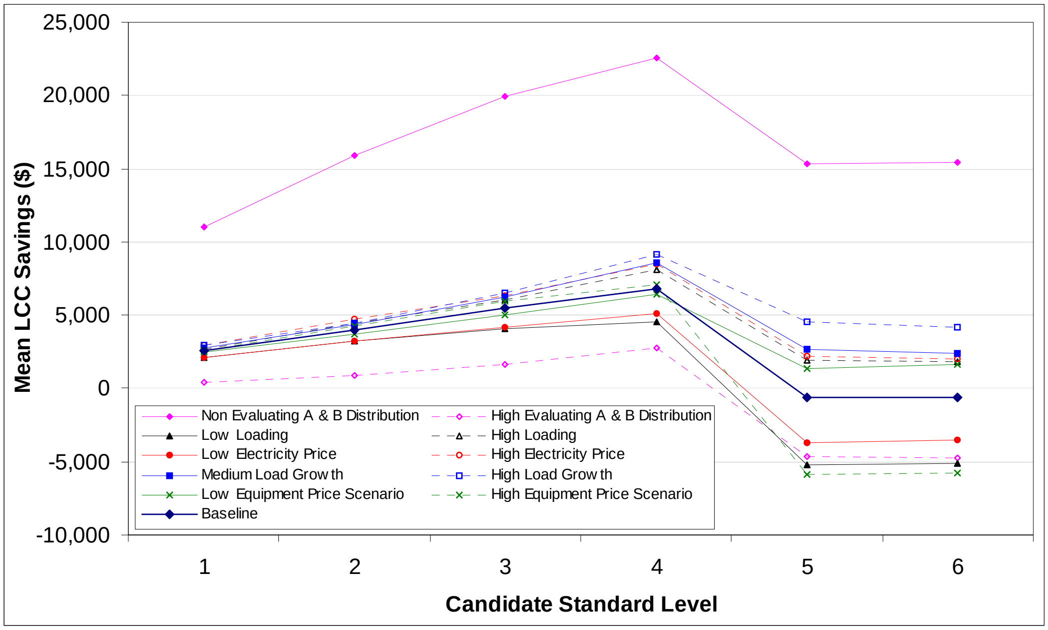

Figure 8.5.3 Design Line 12 Sensitivity Results by Candidate Standard Level

8.6 PAYBACK PERIOD

Payback period (PBP) is a common technique used to evaluate investment decisions analysis. A more energy-efficient device will usually cost more to purchase than a device of standard energy efficiency. However, the more efficient device will usually cost less to operate, due to the reduction in energy use. The payback period is the time (usually expressed in years) it takes to recover the additional first cost of the efficient device with its energy cost savings. Because the LCC analysis uses distributions of inputs, DOE gives results such as payback periods in the form of distributions.

8.6.1 Payback Period

The PBP measures the time it takes the consumer to recover the assumed higher purchase expense (i.e., higher first cost) of more energy-efficient equipment through lower operating costs. Numerically, the PBP is the ratio of the increase in purchase expense (i.e., from a less efficient design to a more efficient design) to the decrease in annual operating expenditures. This type of calculation is known as a *simple* payback period because it does not take into account changes in operating expense over time.

Payback period is found using the equation:

$$PBP = \frac{\Delta FC}{\Delta OC} \qquad \textbf{Eq. 8.8}$$

where:

ΔFC = installed purchase price (first cost) of a transformer satisfying the candidate standard level minus the installed purchase price (first cost) of a transformer in the absence of the standard (assumes the transformer meeting the standard is more expensive than the transformer not subject to the standard) (2004$), and

ΔOC = operating cost of the transformer not subject to the standard minus the operating cost of the transformer subject to the standard (assumes the transformer meeting the candidate standard level has lower energy consumption, and hence lower operating cost, than the transformer not subject to the standard). Because ΔOC is expressed in annual terms, PBP is expressed in years.

8.6.2 Inputs

The inputs to PBP are: 1) the purchase expense, otherwise known as the total installed consumer cost, or first cost, for each selected design; and 2) the annual (first year) operating expenditures for each selected design. The inputs to the purchase expense are the equipment price and the installation cost with appropriate markups. The inputs to the operating costs are the annual (first year) energy consumption and the electricity price. The distributional PBP uses the same inputs as the LCC analysis described in section 8.3, except that, since this is a simple payback, the electricity price the Department used is only for the year the standard takes effect, assumed here to be 2010.

8.6.3 Baseline Scenario Complications

Since distribution transformers are not currently subject to energy-efficiency standards, the Department developed the baseline scenario to estimate transformer purchase behavior in the current market. The Department’s default assumptions for the baseline scenario were that some portion of transformer purchase decisions are based on TOC-type evaluations. Specifically, the default assumptions for use of TOC-type evaluation are 75 percent for liquid-immersed transformers, 50 percent for medium-voltage, dry-type transformers, and 10 percent for low-voltage, dry-type transformers, all using distributions of A and B evaluation factors. Especially at the lower candidate standard levels evaluated by the Department, the transformer purchases based on TOC may not satisfy the basic PBP assumptions of higher purchase price and lower operating costs for the transformers subject to the candidate standard. When these basic assumptions are not satisfied, the traditional PBP calculation loses its validity.

For example, a current (i.e., not subject to standards) transformer purchase decision based on TOC may have identical first cost ($\Delta FC = 0$) to a transformer just meeting TP 1, i.e., candidate standard level 1. In addition, the transformer meeting the standard may have a different operating cost from the transformer purchased without the standard. In such a situation, PBP = 0. In another example, a current transformer purchase decision based on TOC may result in a transformer costing more to purchase and install and consuming less electricity than a transformer that just meets TP 1. In this case, the PBP calculation for the standards case is nonsensical, since it would imply a negative payback period.

The Department's method of calculating PBP is shown below.

$$\Delta FC = FC(Standard) - FC(Baseline)$$

(ΔFC is normally positive)

$$\Delta OC = OC(Standard) - OC(Baseline)$$

(ΔOC is normally negative)

$$PBP = -\Delta FC / \Delta OC$$

(For the normally positive ΔFC and the normally negative ΔOC, PBP is positive)

Because ΔFC can also be zero or negative, and because ΔOC can also be zero or negative, there are nine possible cases that can be grouped into five computational cases. The Department developed Table 8.6.1 to show these nine possible relationships between ΔFC and ΔOC and the resultant effect on PBP.

Table 8.6.1 Possible Cases of ΔFC and ΔOC Combinations, for Payback Period Analysis

Case #	Possible Cases	Effect on PBP Calculation
1	$\Delta FC > 0$ and $\Delta OC < 0$	Well-defined PBP
2	$\Delta FC = 0$ and $\Delta OC = 0$	Unaffected by the standard
3	$\Delta FC < 0$ and $\Delta OC = 0$ $\Delta FC > 0$ and $\Delta OC = 0$	Division by zero: PBP is undefined
4	$\Delta FC = 0$ and $\Delta OC > 0$ $\Delta FC = 0$ and $\Delta OC < 0$	PBP = 0
5	$\Delta FC < 0$ and $\Delta OC < 0$, or $\Delta FC > 0$ and $\Delta OC > 0$, or $\Delta FC < 0$ and $\Delta OC > 0$	Not valid: negative or double negative PBP

8.6.4 Payback Period Results

Tables 8.6.2 through 8.6.14 illustrate, for each of the 13 design lines and their six candidate standard levels, the mean PBP and the percentage of the 10,000 Monte Carlo simulations where the PBP calculation applies. For each candidate standard level for each design line, the sum of the categories “Transformers Unaffected by the Standard,” “Transformers having Well-Defined Payback Period,” and “Transformers having Undefined Payback Period” should equal 100 percent.[a] As the efficiency of the candidate standard levels increases, the percentage of purchase decisions where the PBPs are well-defined increases. A complete set of PBP histograms for all cases presented in these tables is included in Appendix 8A.

8.6.5 Design Line 1 Results

Table 8.6.2 presents the summary of the PBP analysis for the representative unit from design line 1, a 50 kVA, liquid-immersed, single-phase, pad-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.97 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.56 percent, and the consumer equipment cost before installation was $1,382.00.

[a] For simplicity of presentation, Cases 3, 4, and 5 in Table 8.6.1 have been grouped together into the “Transformers having Undefined Payback Period” category in Tables 8.6.2 through 8.6.14.

Table 8.6.2 Summary of Payback Period Results for Design Line 1 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	11.4	21.9	36.0	15.5	24.4	45.0
Transformers Unaffected by the Standard (%)	65.2	50.9	14.7	4.6	2.1	0.0
Transformers having Well-Defined Payback Period (%)	34.0	47.6	81.8	95.1	97.7	99.3
Transformers having Well-Defined Payback Period (%)	0.8	1.5	3.5	0.3	0.2	0.7
Mean Incremental First Cost ($)	166	312	494	509	878	1679
Mean Operating Cost Savings ($)	22	24	23	36	43	46

8.6.6 Design Line 2 Results

Table 8.6.3 presents the summary of the PBP analysis for the representative unit from design line 2, a 25 kVA, liquid-immersed, single-phase, pole-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.74 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.23 percent, and the consumer equipment cost before installation was $737.00.

Table 8.6.3 Summary of Payback Period Results for Design Line 2 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	4.8	6.8	8.8	12.0	31.7	66.6
Transformers Unaffected by the Standard (%)	66.6	64.3	60.8	56.3	25.4	0.0
Transformers having Well-Defined Payback Period (%)	28.3	34.4	37.2	40.9	71.3	100.0
Transformers having Undefined Payback Period (%)	5.1	1.3	2.0	2.8	3.3	0.0
Mean Incremental First Cost ($)	32	49	59	76	239	1,475
Mean Operating Cost Savings ($)	13	13	12	12	12	25

8.6.7 Design Line 3 Results

Table 8.6.4 presents the summary of the PBP analysis for the representative unit from design line 3, a 500 kVA, liquid-immersed, single-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.36 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 99.07 percent, and the consumer equipment cost before installation was $5,428.00.

Table 8.6.4 Summary of Payback Period Results for Design Line 3 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	1.4	4.3	10.4	19.8	29.3	32.3
Transformers Unaffected by the Standard (%)	73.7	65.2	49.5	4.0	0.1	0.0
Transformers having Well-Defined Payback Period (%)	16.8	34.4	50.1	93.5	99.8	100.0
Transformers having Undefined Payback Period (%)	9.6	0.4	0.5	2.6	0.0	0.0
Mean Incremental First Cost ($)	131	628	1,302	1,871	8,287	9,332
Mean Operating Cost Savings ($)	292	303	290	212	397	398

8.6.8 Design Line 4 Results

Table 8.6.5 presents the summary of the PBP analysis for the representative unit from design line 4, a 150 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.91 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.42 percent, and the consumer equipment cost before installation was $3,335.00.

Table 8.6.5 Summary of Payback Period Results for Design Line 4 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	8.5	18.1	21.5	17.0	29.2	34.9
Transformers Unaffected by the Standard (%)	63.7	40.8	11.3	9.7	0.8	0.0
Transformers having Well-Defined Payback Period (%)	35.4	58.3	88.4	90.3	99.0	99.9
Transformers having Undefined Payback Period (%)	1.0	0.9	0.3	0.0	0.3	0.1
Mean Incremental First Cost ($)	484	898	1,543	1,948	3,336	4,195
Mean Operating Cost Savings ($)	93	88	102	136	158	166

8.6.9 Design Line 5 Results

Table 8.6.6 presents the summary of the PBP analysis for the representative unit from design line 5, a 1500 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.36 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 99.13 percent, and the consumer equipment cost before installation was $11,931.00.

Table 8.6.6 Summary of Payback Period Results for Design Line 5 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	3.4	6.1	12.7	14.1	25.6	26.1
Transformers Unaffected by the Standard (%)	71.7	62.8	40.0	24.2	0.0	0.1
Transformers having Well-Defined Payback Period (%)	28.3	37.1	59.1	75.0	99.9	99.9
Transformers having Undefined Payback Period (%)	0.0	0.1	1.0	0.8	0.1	0.1
Mean Incremental First Cost ($)	1,489	2,581	3,066	4,439	19,736	19,728
Mean Operating Cost Savings ($)	638	707	569	574	1,064	1,037

8.6.10 Design Line 6 Results

Table 8.6.7 presents the summary of the PBP analysis for the representative unit from design line 6, a 25 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 95.56 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 94.98 percent, and the consumer equipment cost before installation was $646.00.

Table 8.6.7 Summary of Payback Period Results for Design Line 6 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	1.8	2.0	3.2	4.5	7.9	7.8
Transformers Unaffected by the Standard (%)	8.8	7.0	3.6	0.5	0.0	0.0
Transformers having Well-Defined Payback Period (%)	91.0	92.4	95.8	98.8	99.9	99.9
Transformers having Undefined Payback Period (%)	0.2	0.6	0.7	0.7	0.1	0.1
Mean Incremental First Cost ($)	176	213	342	474	883	884
Mean Operating Cost Savings ($)	136	155	168	174	186	188

8.6.11 Design Line 7 Results

Table 8.6.8 presents the summary of the PBP analysis for the representative unit from design line 7, a 75 kVA, low-voltage, dry-type, three-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 96.31

percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 95.84 percent, and the consumer equipment cost before installation was $1,498.00.

Table 8.6.8 Summary of Payback Period Results for Design Line 7 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	0.8	1.6	2.3	3.9	7.0	7.0
Transformers Unaffected by the Standard (%)	10.1	7.6	6.8	0.7	0.0	0.0
Transformers having Well-Defined Payback Period (%)	89.8	92.2	93.1	98.8	99.9	99.8
Transformers having Undefined Payback Period (%)	0.1	0.1	0.1	0.5	0.1	0.2
Mean Incremental First Cost ($)	151	302	545	904	1,794	1,796
Mean Operating Cost Savings ($)	280	308	363	390	429	432

8.6.12 Design Line 8 Results

Table 8.6.9 presents the summary of the PBP analysis for the representative unit from design line 8, a 300 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.70 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 97.22 percent, and the consumer equipment cost before installation was $3,801.00.

Table 8.6.9 Summary of Payback Period Results for Design Line 8 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	1.0	2.0	2.4	5.8	8.2	7.9
Transformers Unaffected by the Standard (%)	8.6	8.6	6.4	0.1	0.0	0.0
Transformers having Well-Defined Payback Period (%)	90.9	91.4	93.4	99.5	99.9	99.8
Transformers having Undefined Payback Period (%)	0.5	0.1	0.3	0.4	0.2	0.2
Mean Incremental First Cost ($)	248	799	1,132	2,684	4,349	4,345
Mean Operating Cost Savings ($)	555	700	809	918	1,001	1,002

8.6.13 Design Line 9 Results

Table 8.6.10 presents the summary of the PBP analysis for the representative unit from design line 9, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV basic impulse insulation level (BIL). For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.77 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.41 percent, and the consumer equipment cost before installation was $7,510.00.

Table 8.6.10 Summary of Payback Period Results for Design Line 9 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	1.5	2.4	5.4	12.4	21.7	21.5
Transformers Unaffected by the Standard (%)	57.8	46.3	29.7	0.5	0.0	0.0
Transformers having Well-Defined Payback Period (%)	33.0	53.4	69.6	98.6	99.7	99.7
Transformers having Undefined Payback Period (%)	9.1	0.3	0.7	0.8	0.3	0.3
Mean Incremental First Cost ($)	169	396	996	2,528	6,528	6,510
Mean Operating Cost Savings ($)	174	263	350	397	503	508

8.6.14 Design Line 10 Results

Table 8.6.11 presents the summary of the PBP analysis for the representative unit from design line 10, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 45kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.17 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.79 percent, and the consumer equipment cost before installation was $33,584.00.

Table 8.6.11 Summary of Payback Period Results for Design Line 10 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	7.7	8.3	10.0	13.4	28.7	29.4
Transformers Unaffected by the Standard (%)	63.3	56.9	44.4	23.2	0.0	0.0
Transformers having Well-Defined Payback Period (%)	35.9	41.8	55.3	75.7	99.7	99.7
Transformers having Undefined Payback Period (%)	0.8	1.2	0.3	1.1	0.3	0.3
Mean Incremental First Cost ($)	4,085	5,161	6,858	8,382	18,989	19,021
Mean Operating Cost Savings ($)	1,000	1,141	1,236	1,199	1,316	1,315

8.6.15 Design Line 11 Results

Table 8.6.12 presents the summary of the PBP analysis for the representative unit from design line 11, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.42 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.05 percent, and the consumer equipment cost before installation was $10,945.00.

Table 8.6.12 Summary of Payback Period Results for Design Line 11 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	3.8	4.9	7.9	11.8	15.1	14.8
Transformers Unaffected by the Standard (%)	42.5	34.6	18.7	2.3	0.0	0.0
Transformers having Well-Defined Payback Period (%)	57.2	64.5	80.1	96.3	99.6	99.6
Transformers having Undefined Payback Period (%)	0.4	0.8	1.1	1.4	0.4	0.4
Mean Incremental First Cost ($)	733	1,263	1,991	3,058	4,399	4,412
Mean Operating Cost Savings ($)	332	445	484	525	556	567

8.6.16 Design Line 12 Results

Table 8.6.13 presents the summary of the PBP analysis for the representative unit from design line 12, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 95kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.18 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.81 percent, and the consumer equipment cost before installation was $33,590.00.

Table 8.6.13 Summary of Payback Period Results for Design Line 12 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	4.6	4.7	8.3	12.7	29.3	29.3
Transformers Unaffected by the Standard (%)	75.1	71.9	56.9	28.2	0.0	0.0
Transformers having Well-Defined Payback Period (%)	24.7	27.9	42.3	69.9	99.7	99.9
Transformers having Undefined Payback Period (%)	0.2	0.2	0.8	1.8	0.3	0.2
Mean Incremental First Cost ($)	2,125	3,204	4,500	6,356	20,409	20,440
Mean Operating Cost Savings ($)	827	1,127	1,129	1,051	1,290	1,286

8.6.17 Design Line 13 Results

Table 8.6.14 presents the summary of the PBP analysis for the representative unit from design line 13, a 2000 kVA, medium-voltage, dry-type, three-phase transformer with a 125kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.26 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.97 percent, and the consumer equipment cost before installation was $41,873.00.

Table 8.6.14 Summary of Payback Period Results for Design Line 13 Representative Unit

	Candidate Standard Level					
	1 (TP 1)	**2**	**3**	**4**	**5**	**6**
Mean Payback Period (Years)	9.7	5.8	8.0	19.5	32.5	32.4
Transformers Unaffected by the Standard (%)	76.0	72.9	58.9	5.4	0.0	0.0
Transformers having Well-Defined Payback Period (%)	23.6	27.0	40.2	93.6	99.8	99.8
Transformers having Undefined Payback Period (%)	0.4	0.1	1.0	1.1	0.2	0.2
Mean Incremental First Cost ($)	1,230	3,614	5,668	10,087	29,292	29,128
Mean Operating Cost Savings ($)	265	987	1,240	1,107	1,562	1,556

8.7 Rebuttable Presumption

The rebuttable presumption is a simplified method of determining the economic justification of a proposed energy efficiency standard. In evaluating the rebuttable presumption, the Department estimates the additional cost of purchasing a more efficient, standard-compliant product, and compares this cost to the value of the energy savings during the first year of operation of the product as determined by the applicable test procedure. If the additional purchase price is less than three times the value of the energy savings, then there shall be a rebuttable presumption that such a standard level is economically justified.

The Department evaluates the rebuttable presumption by calculating a rebuttable payback period, where the rebuttable payback period is the ratio of the value of the first year's energy savings determined from the applicable energy savings to the increase in purchase price. When the rebuttable payback period is less than three years, the rebuttable presumption is satisfied, and when it is equal to or more than three years the rebuttable presumption is not satisfied.

The rebuttable payback period differs from payback periods presented in other parts of this chapter in at least two important ways:

- The rebuttable payback period uses test procedure loading levels to evaluate losses, rather than the Department’s estimate of in-service loading conditions.

- The rebuttable payback period uses incremental purchase price rather than the incremental installed cost as the incremental first cost of improved efficiency.

There are three key inputs into the rebuttable payback calculation: (1) the average efficiency; (2) the average purchase price; and (3) the cost of electricity. Given the average efficiency of the transformer, the Department calculates the losses on the transformer assuming the loading conditions from the test procedure. Multiplying the losses times the cost of electricity provides the operating cost, and then dividing incremental operating costs into incremental purchase price provides the estimate of the rebuttable payback period.

Tables 8.7.1 through 8.7.4 show the different inputs into the rebuttable presumption payback period calculation. Table 8.7.1 shows the average transformer efficiency as a function of design line and standard level. This is the average efficiency as determined by the customer choice model of the LCC calculation. The customer choice model provides a range of transformer design efficiencies that depends on a distribution of customer choices with respect to the value that customers place on reducing transformer design losses. Table 8.7.2 shows the average transformer purchase price as a function of both design line and standard level. Table 8.7.3 shows the average marginal cost of electricity as a function of both design line and standard level. There is a substantial difference between the marginal cost of electricity for liquid-immersed and dry-type transformers because liquid-immersed transformers tend to be owned by utilities which pay the wholesale (rather than retail) cost of electricity. Table 8.7.4 shows the first year operating cost, which is the annual losses calculated from the test procedure assumptions times the average marginal cost of electricity.

Table 8.7.5 shows the rebuttable payback period as a function of design line and standard level. The table records how the rebuttable presumption is not satisfied for any candidate level for design lines 1, 2, 4, 10, and 13. For design line 5, it is satisfied for candidate standard level 1 only. For design lines 3, 11, and 12, it is satisfied for candidate standard levels 1 and 2. For design line 9, it is satisfied for levels 1 through 3, while for all of the low-voltage, dry-type design lines (DLs 6-8), it is satisfied for levels 1 through 4.

Assuming the design line results are representative of the corresponding rated capacity ranges as specified in the engineering chapter (Chapter 5), the rebuttable presumption results by product class are as follows: The rebuttable presumption condition is not satisfied for product class 1 for any candidate standard level for the small size categories, while for the larger rated capacities it is satisfied for levels 1 and 2. For product class 2 (three-phase, liquid-immersed transformers), the rebuttable presumption is satisfied for only candidate standard level 1 for the larger rated capacities. For product classes 3 and 4, the rebuttable presumption is satisfied for levels 1 through 4. For product classes 5 and 6, the rebuttable presumption is satisfied for candidate standard levels 1 through 3 for the smaller rated capacities, and not satisfied at all for the larger transformers. For product classes 7 and 8, the rebuttable presumption is satisfied for levels 1 and 2 for all rated capacities. And for product classes 9 and 10, the rebuttable presumption is not satisfied for any candidate standard level.

Table 8.7.1 Average Transformer Efficiency

Design Line	Rated Capacity *kVA*	Base %	CSL 1 (TP 1) %	CSL 2 %	CSL 3 %	CSL 4 %	CSL 5 %	CSL 6 %
1	50	98.97	99.06	99.12	99.23	99.39	99.50	99.59
2	25	98.74	98.84	98.86	98.87	98.88	98.99	99.47
3	500	99.36	99.43	99.46	99.49	99.55	99.74	99.75
4	150	98.91	99.06	99.16	99.33	99.48	99.59	99.61
5	1,500	99.36	99.41	99.44	99.46	99.49	99.71	99.71
6	25	95.56	98.08	98.27	98.48	98.67	98.91	98.91
7	75	96.31	98.15	98.37	98.68	98.96	99.14	99.14
8	300	97.70	98.66	98.94	99.06	99.27	99.34	99.34
9	300	98.77	98.86	98.96	99.08	99.26	99.41	99.41
10	1,500	99.17	99.26	99.30	99.35	99.41	99.51	99.51
11	300	98.42	98.66	98.76	98.89	99.03	99.11	99.11
12	1,500	99.18	99.24	99.27	99.30	99.37	99.52	99.52
13	2,000	99.26	99.27	99.31	99.36	99.46	99.56	99.56

Table 8.7.2 Average Transformer Purchase Price

Design Line	Rated Capacity *kVA*	Base *$*	CSL 1 (TP 1) *$*	CSL 2 *$*	CSL 3 *$*	CSL 4 *$*	CSL 5 *$*	CSL 6 *$*
1	50	1,402	1,444	1,509	1,701	1,971	2,258	2,901
2	25	789	805	810	816	822	911	1,894
3	500	5,348	5,422	5,567	5,956	7,003	12,938	13,923
4	150	3,511	3,660	3,961	4,855	5,319	6,635	7,396
5	1,500	13,926	14,289	14,845	15,608	17,191	32,793	32,795
6	25	653	800	830	909	1,012	1,329	1,329
7	75	1,518	1,685	1,801	1,993	2,321	3,019	3,019
8	300	3,835	4,079	4,577	4,834	6,317	7,758	7,757
9	300	7,586	7,652	7,791	8,223	9,891	13,539	13,536
10	1,500	29,127	30,412	31,239	32,787	35,214	47,083	47,079
11	300	11,037	11,452	11,803	12,541	13,808	15,059	15,059
12	1,500	32,116	32,642	32,999	33,841	36,443	51,594	51,618
13	2,000	40,376	40,675	41,277	42,592	49,443	68,333	68,340

Table 8.7.3 Average Marginal Electricity Cost

Design Line	Rated Capacity *kVA*	Base *$*	CSL 1 (TP 1) *$*	CSL 2 *$*	CSL 3 *$*	CSL 4 *$*	CSL 5 *$*	CSL 6 *$*
1	50	0.044	0.045	0.044	0.043	0.048	0.046	0.043
2	25	0.043	0.043	0.043	0.043	0.043	0.043	0.043
3	500	0.043	0.043	0.043	0.043	0.043	0.044	0.043
4	150	0.043	0.043	0.043	0.045	0.045	0.043	0.043
5	1,500	0.042	0.042	0.042	0.042	0.042	0.042	0.042
6	25	0.071	0.075	0.074	0.073	0.073	0.073	0.073
7	75	0.068	0.071	0.072	0.072	0.072	0.071	0.071
8	300	0.067	0.070	0.072	0.072	0.072	0.070	0.070
9	300	0.067	0.067	0.067	0.067	0.066	0.066	0.066
10	1,500	0.066	0.066	0.066	0.066	0.066	0.065	0.065
11	300	0.067	0.068	0.067	0.067	0.067	0.067	0.067
12	1,500	0.066	0.066	0.066	0.066	0.065	0.064	0.064
13	2,000	0.065	0.065	0.066	0.066	0.065	0.064	0.064

Table 8.7.4 First Year Operating Cost for Rebuttable Presumption, Based on DOE Test Procedure

Design Line	Rated Capacity *kVA*	Base *$*	CSL 1 (TP 1) *$*	CSL 2 *$*	CSL 3 *$*	CSL 4 *$*	CSL 5 *$*	CSL 6 *$*
1	50	101	92	86	74	65	51	39
2	25	60	55	55	54	53	48	25
3	500	610	537	514	479	423	247	237
4	150	311	267	238	197	155	119	109
5	1,500	1,782	1,628	1,555	1,495	1,399	799	799
6	25	252	112	100	87	75	61	61
7	75	596	308	272	221	173	141	142
8	300	1,459	877	711	627	488	430	430
9	300	1,090	1,012	930	816	646	512	512
10	1,500	3,614	3,197	3,037	2,816	2,564	2,081	2,081
11	300	1,419	1,205	1,108	994	858	794	794
12	1,500	3,564	3,322	3,191	3,027	2,716	2,058	2,057
13	2,000	4,264	4,200	3,981	3,710	3,114	2,515	2,515

Table 8.7.5 Rebuttable Payback for Rebuttable Presumption Period

Design Line	Rated Capacity *kVA*	CSL 1 (TP 1) *yrs*	CSL 2 *yrs*	CSL 3 *yrs*	CSL 4 *yrs*	CSL 5 *yrs*	CSL 6 *yrs*
1	50	5.1	7.1	11.3	16.1	17.1	24.3
2	25	3.7	4.3	4.7	5.3	10.4	31.8
3	500	1.0 *	2.3 *	4.6	8.9	20.9	23.0
4	150	3.4	6.2	11.8	11.6	16.2	19.2
5	1,500	2.4 *	4.1	5.9	8.5	19.2	19.2
6	25	1.1 *	1.2 *	1.5 *	2.0 *	3.5	3.5
7	75	0.6 *	0.9 *	1.3 *	1.9 *	3.3	3.3
8	300	0.4 *	1.0 *	1.2 *	2.6 *	3.8	3.8
9	300	0.9 *	1.3 *	2.3 *	5.2	10.3	10.3
10	1,500	3.1	3.7	4.6	5.8	11.7	11.7
11	300	1.9 *	2.5 *	3.5	4.9	6.4	6.4
12	1,500	2.2 *	2.4 *	3.2	5.1	12.9	12.9
13	2,000	4.7	3.2	4.0	7.9	16.0	16.0

* Values less than 3 indicate a rebuttable presumption that the standard level is economically justified.

8.8 USER INSTRUCTIONS FOR SPREADSHEETS

To execute the LCC spreadsheet, it is necessary for the user to have the appropriate hardware and software tools. The Department assumed the user has a reasonably current computer operating under the Windows operating system. The development team uses relatively new systems and has not defined the minimum system requirements. At a minimum, users need Microsoft Excel to execute the spreadsheet. For full functionality in running Monte Carlo simulations, users will need a copy of a spreadsheet add-in called Crystal Ball, in addition to Excel. Without Crystal Ball, one can still use the LCC spreadsheet model, but will not be able to examine inputs and outputs as distributions. Approximate results are provided through a sample calculation that uses average values for the inputs and outputs, as displayed in the "Summary" worksheet.

8.8.1 Startup

The LCC spreadsheet is a stored Excel file. Open the file. (Each computer system will have a unique setup for loading a file. Users should refer to their software manuals if they have problems loading the spreadsheet file.) For users new to Excel and/or Crystal Ball, section 8.7.2 contains basic instructions for operating the LCC spreadsheets.

8.8.1.1 Sheet Overview

Each of the LCC spreadsheets for the 5 liquid-immersed transformer design lines contain the following 17 worksheets:

- Options
- Description
- Summary
- A & B Distribution
- Design Table
- Load & Price Parameters
- Utilities
- Discount Rate
- Hourly Loads
- Hourly Prices
- Annual Energy Price Forecast
- Baseline LCC
- Design Option LCC
- Lifetime
- Load-Price Charts
- Results - LLvNL
- LL vs NL

Each of the LCC spreadsheets for the 8 dry-type transformer design lines contain the following 17 worksheets:

- Description
- Summary
- A & B Distribution
- Design Table
- Demand & Usage

- Utilities
- Discount Rate
- Annual Energy Price Forecast
- Baseline LCC
- Design Option LCC
- Lifetime
- Load-Price Charts
- Results - LLvNL
- LL vs NL
- Tariffs
- Components
- Options

Most of the worksheets consist of the data inputs used in the spreadsheet calculations. To assure functionality in the spreadsheet model while maintaining reasonable size, DOE pre-processed some variables into a representative equation. “Hourly Loads” and “Hourly Prices” are the two best examples of using an equation (Fourier transform) to express a complex set of data in an equation. The “Load-Price Charts” worksheet provides a graphical expression of the “Hourly Loads” and “Hourly Prices.”

The spreadsheet/user interface is centered in the “Summary” worksheet. This worksheet contains a number of user-selectable options. These options, each with its own pull-down menu, are:

- Candidate Standard Level
- Transformer Load Growth/Year
- Transformer Loading
- Electricity Prices
- Transformer Customer A’s & B’s
- Future Energy Price Trend
- Equipment Price Scenario (liquid-immersed only)
- Efficiency Standard Effective Date

Changing user-selectable options will produce average results shown on the “Summary,” i.e., results using the mean inputs. Because of the very nature of Monte Carlo mathematics, the average results will not be identical to the mean of the distribution produced from Monte Carlo Crystal Ball simulations, but will provide quick feedback reflecting nominal results to spreadsheet users. The Department conducted an example Monte Carlo run of 100 iterations to produce “Results-LLvNL” which is shown graphically as “LL vs NL.” Selecting different standard levels in the “Summary” worksheet will produce a different graphical result on the “LL vs NL” sheet, as well as different average results on the “Summary” worksheet.

8.8.2 Basic Instructions for Operating the Life-Cycle Cost Spreadsheets

1. Once you have downloaded the LCC file from the Web, open the file using Excel. At the bottom, click on the tab for sheet "Summary."
2. Use Excel's View/Zoom commands at the top menu bar to change the size of the display to make it fit your monitor.
3. The user interacts with the spreadsheet by clicking choices or entering data using the graphical interface that comes with the spreadsheet. Select choices from the various user-selectable options.

To produce sensitivity results using Crystal Ball, select *Run* from the *Run* menu (on the menu bar). To make basic changes in the *Run* sequence, including altering the number of trials, select *Run Preferences* from the *Run* menu. After each simulation run, the user needs to select *Reset* (also from the *Run* menu) before *Run* can be selected again. Once Crystal Ball has completed its run sequence, it will produce a series of distributions. Using the menu bars on the distribution results, it is possible to obtain further statistical information. The time taken to complete a run sequence can be reduced by minimizing the Crystal Ball window in Excel. A step-by-step summary of the procedure for running a distribution analysis is outlined below:

1. Find the Crystal Ball toolbar (at top of screen).
2. Click on *Run* from the menu bar.
3. Select *Run Preferences* and choose either Monte Carlo or Latin Hypercube.[a] Select number of Trials (the Department suggests 10,000).
4. To run the simulation, choose the following sequence (on the Crystal Ball toolbar)
   Run
   Reset
   Run
5. Now wait until the program informs you that the simulation is completed.

The Department provides the following instructions to view the output generated by Crystal Ball:

1. After the simulation has finished, click on the Windows tab bar labeled Crystal Ball to see the distribution charts.

2. The LCC savings and paybacks are defined as *Forecast* cells. The frequency charts display the results of the simulations, or trials, performed by Crystal Ball. Click on any chart to bring it into view. The charts show the low and high endpoints of the forecasts.

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[a] Because of the nature of the program, there is some variation in results due to random sampling when Monte Carlo or Latin Hypercube sampling is used.

The *View* selection on the Crystal Ball toolbar can be used to specify whether cumulative or frequency plots are to be shown.

2a.
To calculate the probability that a particular value of LCC savings will occur, either type 0 in the box by the left arrow, or move the arrow key with the cursor to 0 on the scale. The value in the *Certainty* box shows the likelihood that the LCC savings will occur.

2b.
To calculate the certainty of the payback period being below a certain number of years, insert that value in the far-right box.

3. To generate a printed report, select *Create Report* from the *Run* menu. The toolbar choice of *Forecast Windows* allows you to select the charts and statistics in which you are interested. For further information on Crystal Ball outputs, refer to *Understanding the Forecast Chart* in the Crystal Ball manual.

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